THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to what action you should take, you should seek your own independent advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who specialises in advising on the acquisition of shares and other securities and is authorised under the Financial Services and Markets Act 2000 (as amended) ("**FSMA**"). If you are resident outside of the United Kingdom ("**UK**"), you should seek advice from a person duly qualified in your jurisdiction who specialises in advising on the acquisition of shares and other securities.

This document, which comprises an AIM admission document drawn up in accordance with the AIM Rules for Companies ("**AIM Rules**"), has been issued in connection with an application for admission to trading on AIM of the entire issued share capital of United Oil & Gas PLC (the "**Company**"). This document does not constitute an offer or any part of any offer of transferable securities to the public within the meaning of section 102B of FSMA or otherwise. Accordingly, this document does not constitute a prospectus for the purposes of section 85 of FSMA or otherwise, and has not been drawn up in accordance with the Prospectus Rules or filed with or approved by the Financial Conduct Authority ("**FCA**") or any other competent authority.

The Company and the Directors, whose names appear on page 7 of this document, accept responsibility, collectively and individually, for the information contained in this document and for compliance with the AIM Rules. To the best of the knowledge and belief of the Company and the Directors (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. To the extent that information has been sourced from a third party, this information has been accurately reproduced and, as far as the Directors are aware, no facts have been omitted which may render the reproduced information inaccurate or misleading. In connection with this document, no person is authorised to give any information or make any representation other than as set out in this document.

Application will be made for the Ordinary Shares to be admitted to trading on AIM. It is expected that Admission will become effective and dealings in the Ordinary Shares will commence on AIM at 8.00 a.m. on 1 March 2019.

AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the United Kingdom Listing Authority (the "Official List") and the AIM Rules are less demanding than those of the Official List. It is emphasised that no application is being made for admission of the Shares to trading on the Official List. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this document.

INVESTMENT IN THE COMPANY IS SPECULATIVE AND INVOLVES A HIGH DEGREE OF RISK. THE WHOLE OF THIS DOCUMENT SHOULD BE READ AND IN PARTICULAR YOUR ATTENTION IS DRAWN TO THE SECTION ENTITLED "RISK FACTORS" SET OUT IN PART III OF THIS DOCUMENT, WHICH DESCRIBES CERTAIN RISKS ASSOCIATED WITH AN INVESTMENT IN THE COMPANY.

UNITED OIL & GAS PLC

(Incorporated and Registered in England and Wales under the Companies Act 2006 with registered number 09624969)

Admission to trading on AIM

BEAUMONT CORNISH Limited

Nominated Adviser

OPTIVA SECURITIES THE GLOBAL INVESTOR

Nominated Broker

Beaumont Cornish Limited ("**BCL**"), which is authorised and regulated in the UK by the FCA, is acting exclusively for the Company as nominated adviser in connection with Admission, and will not be responsible to any other person for providing the protections afforded to the clients of BCL or advising any other person in connection with Admission. BCL's responsibilities as the Company's nominated adviser under the AIM Rules for Companies and the AIM Rules for Nominated Advisers will be owed solely to the London Stock Exchange and not to the Company, the Directors or to any other person in respect of such person's decision to subscribe for or acquire Shares in reliance on any part of this document. Apart from the responsibilities and liabilities, if any, which may be imposed on BCL by FSMA or the regulatory regime established under it, BCL does not accept any responsibility whatsoever for the contents of this document. BCL has not authorised the contents of this document and no representation or warranty, express or implied, is made by it as to the accuracy or contents of this document or the opinions contained herein. The information contained in this document is not intended to inform or be relied upon by any subsequent purchasers of Shares (whether on or off market) and accordingly no duty of care is accepted by BCL in relation to them. No person has been authorised to give any information or make any representations other than those contained in this document and, if given or made, such information or representations must not be relied upon as having been so authorised. The delivery of this document will not, under any circumstances, be deemed to create any implication that there has been no change in the affairs of the Company since the date of this document or that the information in this document is correct at any time subsequent to its date.

Optiva Securities Limited ("**Optiva**"), a firm which is authorised and regulated in the United Kingdom by the FCA, is acting exclusively for the Company as broker in connection with the Admission, and will not be responsible for any other person for providing the protections afforded to the clients of Optiva or advising any other person in connection with the Admission. Apart from the responsibilities and liabilities, if any, which may be imposed on Optiva by FSMA or the regulatory regime established under it, Optiva does not accept any responsibility whatsoever for the contents of this document or any part of it.

This document does not constitute an offer to sell, or a solicitation to buy or subscribe for, securities in any jurisdiction in which such offer or solicitation is unlawful. The distribution of this document in certain jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe such restrictions. Any such distribution could result in a violation of the laws of such jurisdictions. In particular, this document is not for publication or distribution in or into the United States, Canada, New Zealand, the Republic of South Africa or Japan, nor in any other country or territory where to do so would contravene local securities laws or regulations. The distribution of this document in other jurisdictions may be restricted by law and therefore persons into whose possession this document comes should inform themselves about and observe any such restriction. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdictions. The Shares have not been, nor will they be, registered under the securities laws of any State of the United States or any province or territory of Canada, New Zealand, the Republic of South Africa or Japan. Accordingly, the Shares may not be offered or sold, directly or indirectly, in or into the United States, Canada, New Zealand, the Republic of South Africa or Japan.

Holding Ordinary Shares may have implications for overseas shareholders under the laws of the relevant overseas jurisdictions. Overseas investors should inform themselves about and observe any applicable legal requirements. It is the responsibility of each overseas shareholder to satisfy themselves as to the full observance of the laws of the relevant jurisdiction in connection therewith, including the obtaining of any governmental, exchange control or other consents which may be required, or the compliance with other necessary formalities which are required to be observed and the payment of any issue, transfer or other taxes due in such jurisdiction.

Copies of this document will be available free of charge during normal business hours on weekdays (excluding Saturdays, Sundays and public holidays) from the date hereof until one month after Admission at the registered offices of the Company and the offices of Beaumont Cornish Limited at 10th Floor, 30 Crown Place, London EC2A 4EB. This document is also available on the Company's website: www.uogplc.com.

Forward looking statements Advisory

Certain statements in this document are or may constitute forward looking statements, including statements about current beliefs and expectations of the Directors. In particular, the words "expect", "anticipate", "estimate", "may", "should", "plan", "intend", "will", "would", "could", "target", "believe" and similar expressions (or in each case their negative and other variations or comparable terminology) can be used to identify forward looking statements. Such forward looking statements are based on the Board's expectations of external conditions and events, current business strategy, plans and the other objectives of management for future operations, and estimates and projections of the Group's financial performance. Though the Board believes these expectations to be reasonable at the date of this document they may prove to be erroneous. Forward looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, achievements or performance of the Group, or the industry in which the Group operates, to be materially different from any future results, achievements or performance expressed or implied by such forward looking statements. These risks and factors include, but are not limited to, risks relating to the Company's ability to execute its exploration and development programme, drilling and operating risks, dependence on key personnel, compliance with environmental regulations and competition. Any forward looking statement in this document speaks only as of the date it is made.

Forward looking statements and other information contained herein concerning the oil and natural gas industry in the countries in which the Company operates and the Company's general expectations concerning this industry are based on estimates prepared by the Company's management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Actual results, performance or achievement could differ materially from that expressed in, or implied by any forward looking statements or information in this document, and accordingly, investors should not place undue reliance on any such forward looking statements or information. Further, any forward looking statement or information speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward looking statements or information to reflect information, events, results, circumstances or otherwise after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law including securities laws and/or the AIM Rules for Companies. All forward looking statements and information contained in this document and other documents of the Company are qualified by such cautionary statements. New factors emerge from time to time, and it is not possible for the Company's management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statements.

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IMPORTANT INFORMATION

Investment considerations

In making an investment decision, prospective investors must rely on their own examination, analysis and enquiry of the Group, this Document and the terms of the Admission, including the merits and risks involved. The contents of this Document are not to be construed as advice relating to legal, financial, taxation, investment decisions or any other matter. Investors should inform themselves as to:

– the legal requirements within their own countries for the purchase, holding, transfer or other disposal of the Ordinary Shares;

– any foreign exchange restrictions applicable to the purchase, holding, transfer or other disposal of the Ordinary Shares which they might encounter; and

– the income and other tax consequences which may apply in their own countries as a result of the purchase, holding, transfer or other disposal of the Ordinary Shares or distributions by the Company, either on a liquidation and distribution or otherwise. Prospective investors must rely upon their own representatives, including their own legal advisers and accountants, as to legal, tax, investment or any other related matters concerning the Company and an investment therein.

An investment in the Company should be regarded as a long-term investment. There can be no assurance that the Group's objectives will be achieved.

It should be remembered that the price of the Ordinary Shares and any income from such Ordinary Shares can go down as well as up.

This Document should be read in its entirety before making any investment in the Ordinary Shares. All Shareholders are entitled to the benefit of, are bound by, and are deemed to have notice of, the provisions of the Articles, which investors should review.

Data protection

The Company may delegate certain administrative functions to third parties and will require such third parties to comply with data protection and regulatory requirements of any jurisdiction in which data processing occurs. Such information will be held and processed by the Company (or any third party, functionary or agent appointed by the Company) for the following purposes:

(a) verifying the identity of the prospective investor to comply with statutory and regulatory requirements in relation to anti-money laundering procedures;

(b) carrying out the business of the Group and the administering of interests in the Group;

(c) meeting the legal, regulatory, reporting and/or financial obligations of the Group in the United Kingdom or elsewhere; and

(d) disclosing personal data to other functionaries of, or advisers to, the Group to operate and/or administer the Company.

Where appropriate it may be necessary for the Company (or any third party, functionary or agent appointed by the Company) to:

(a) disclose personal data to third party service providers, agents or functionaries appointed by the Company to provide services to prospective investors; and

(b) transfer personal data outside of the EEA to countries or territories which do not offer the same level of protection for the rights and freedoms of prospective investors as the United Kingdom.

If the Company (or any third party, functionary or agent appointed by the Company) discloses personal data to such a third party, agent or functionary and/or makes such a transfer of personal data, it will use reasonable endeavours to ensure that any third party, agent or functionary to whom the relevant personal data is disclosed or transferred is contractually bound to provide an adequate level of protection in respect of such personal data.

In providing such personal data, investors will be deemed to have agreed to the processing of such personal data in the manner described above. Prospective investors are responsible for informing any third party individual to whom the personal data relates of the disclosure and use of such data in accordance with these provisions.

Extraction of information from the Competent Person's Report

This Document contains cross-references to information contained in the Competent Person's Reports set out in Part VIII and Part IX of this Document. The Company confirms that the information which has been extracted from the Competent Person's Reports has been accurately reproduced and that so far as the Company is aware and is able to ascertain from the Competent Person's Reports, no facts have been omitted which would render the extracts inaccurate or misleading. Each Competent Person has reviewed the information contained in this Document which relates to information contained in the respective Competent Person's Report and has confirmed in writing to the Company, and Beaumont Cornish, that the information presented is accurate, balanced and complete and not inconsistent with the Competent Person's Report.

Third party data

This Document includes certain market, economic and industry data, which was obtained by the Company from industry publications, data and reports, compiled by professional organisations and analysts' data from other external sources conducted by or on behalf of the Company. Where information contained in this Document originates from a third party source, it is identified where it appears in this Document together with the name of its source. The Company confirms that data sourced from third parties used to prepare the disclosures in this Document has been accurately reproduced and, so far as the Company and the Directors are aware, and able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. All third party information is identified alongside where it is used.

Certain of the aforementioned third party sources may state that the information they contain has been obtained from sources believed to be reliable. However, such third party sources may also state that the accuracy and completeness of such information is not guaranteed and that the projections they contain are based on significant assumptions. As the Company does not have access to the facts and assumptions underlying such market data, statistical information and economic indicators included in these third party sources, the Company is unable to verify such information.

Currency presentation

Unless otherwise indicated, all references in this Document to "UK Sterling", "pound sterling", "sterling", "£", or "pounds" or "pence" are to the lawful currency of the UK, all references to "EUR", "€" or "euro cents" are to the lawful currency of the EU. In addition all references to "USD", "US$", "US dollar" or "cents" are to the lawful currency of the United States.

No incorporation of website

The contents of any website of the Company or any other person do not form part of this Document.

Definitions and glossary of technical terms

A list of defined terms used in this Document is set out in Part X 'Definitions' and a list of technical terms and their meanings used in this Document is referred to in Part XI 'Glossary of Technical Terms', and set out in the glossaries of technical terms contained in Parts VIII and IX.

Governing law

Unless otherwise stated, statements made in this Document or documents incorporated herein by reference are based on the law and practice currently in force in England and Wales and are subject to changes therein.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Publication of this Document	22 February 2019
Cancellation of listing on the Official List	8.00 a.m. on 1 March 2019
Admission to trading effective and commencement of dealings on AIM	8.00 a.m. on 1 March 2019

All references to time in this Document are to London time unless otherwise stated.

SHARE CAPITAL

Number of Ordinary Shares in issue as at the date of this Document and on Admission	345,613,985
Last closing mid-market price on 22 February 2019 (being the latest practicable date)	4.10p
Estimated market capitalisation on Admission (based on the last closing mid-market price on 22 February 2019)	£14.17 million
Number of Warrants in issue as at the date of this Document and on Admission	82,212,206
Number of Options in issue as at the date of this Document and on Admission	11,117,648

DEALING CODES

ISIN	GB00BYX0MB92
SEDOL	BYX0MB9
LEI	213800WZWERBFYBQ9J17Q9J17
TIDM	UOG

DIRECTORS, SECRETARY AND ADVISERS

Directors:	Alan Graham Martin, *Non-Executive Chairman* Brian Edward Andrew Larkin, *Chief Executive Officer* Jonathan James Leather, *Chief Operating Officer* Alberto Cattaruzza, *Non-Executive Director* *whose business address is at:* 9 Upper Pembroke Street Dublin 2 Ireland *and the registered office is at:* 200 Strand London WC2R 1DJ Telephone: +353 1 905 3557
Company Secretary:	Brian Edward Andrew Larkin
Website:	www.uogplc.com
Nominated Adviser:	Beaumont Cornish Limited 10th Floor 30 Crown Place London EC2A 4EB
Broker:	Optiva Securities Limited 49 Berkeley Square Mayfair London W1J 5AZ
Reporting Accountants and Auditors:	UHY Hacker Young LLP Quadrant House 4 Thomas More Square London E1W 1YW
Legal advisers to the Company as to English law:	Kerman & Co LLP 200 Strand London WC2R 1DJ
Legal advisers to the Company as to Jamaican law:	Dunn Cox 48 Duke Street Kingston Jamaica
Legal advisers to the Company as to Italian law:	Studio Legal Turco Viale Gioacchino Rossini 9 00198 Rome Italy
Legal advisers to the Nominated Adviser and Broker:	DMH Stallard LLP 6 New Street Square New Fetter Lane London EC4A 3BF

Registrar:	Share Registrars Limited 17 West Street Farnham Surrey GU9 7SR
Competent Persons:	ERC Equipoise Ltd 6th Floor Stephenson House 2 Cherry Orchard Road Croydon CR0 6BA CGG Services (UK) Limited Crompton Way, Manor Royal Estate Crawley West Sussex RH10 9QN

PART I

INFORMATION ON THE GROUP

1. Introduction

United Oil & Gas Plc is an oil and gas exploration and development company established in 2015 and admitted to trading on the standard segment of the London Stock Exchange's Main Market for listed securities. The Company has a multi-stage portfolio of low risk European development and appraisal assets and exploration assets in Jamaica.

The Company's strategy is to build a portfolio of production, development and low-risk appraisal/exploration oil and gas assets in Europe, whilst remaining alert for exceptional growth opportunities on a global basis – primarily in Caribbean, Latin America and Africa.

2. Background

The Company was admitted to a listing on the Official List by way of a Standard Listing in accordance with Chapter 14 of the Listing Rules and to trading on the London Stock Exchange's Main Market for listed securities, on 10 November 2015.

Following the successful acquisition of UOG UK (together with its subsidiaries) and a contemporaneous placing which raised £3 million (before expenses) the Company was readmitted to a listing on the Official List by way of a Standard Listing in accordance with Chapter 14 of the Listing Rules and to trading on the London Stock Exchange's Main Market for listed securities on 31 July 2017.

In December 2017, the Company completed a placing of 31,250,000 Ordinary Shares at a price of 4 pence per Ordinary Share raising in aggregate £1.25 million (before expenses) to support entry into further oil and gas asset projects.

In April 2018, the Company carried out a placing of 57,411,766 new Ordinary Shares and a subscription of 1,411,764 new Ordinary Shares at a price of 4.25 pence per Ordinary Share raising in aggregate £2.5 million (before expenses) to support the business growth of the Group, in particular to finance the work programme on the existing assets in its portfolio.

In September 2018, the Company completed a placing of 20,251,548 new Ordinary Shares and a subscription of 34,293,906 new Ordinary Shares at a price of 5.5 pence per Ordinary Share raising in aggregate £3 million (before expenses) to pursue new projects in line with dual Company focus to build a portfolio of low risk, late stage appraisal/development projects in Europe and high impact exploration plays in the Caribbean, Latin America and Africa.

The Company is now seeking to apply for the admission of its issued ordinary share capital to trading on AIM and seek a simultaneous cancellation from the standard segment of the Official List.

3. Business Overview, Structure and Projects

3.1 *Overview*

The Directors have a proven track record of successfully evaluating and recommending farm-in deals, and actively seek appropriate opportunities to acquire assets in which full value is not currently being realised.

As at the date of this Document, the Company has a number of directly held oil and gas assets located in the UK, Italy and Jamaica in development of which it is actively involved. These are outlined in the UOG Current Assets table and their geographic spread is presented in the UOG Current Portfolio Overview figure below.

UOG Current Assets:

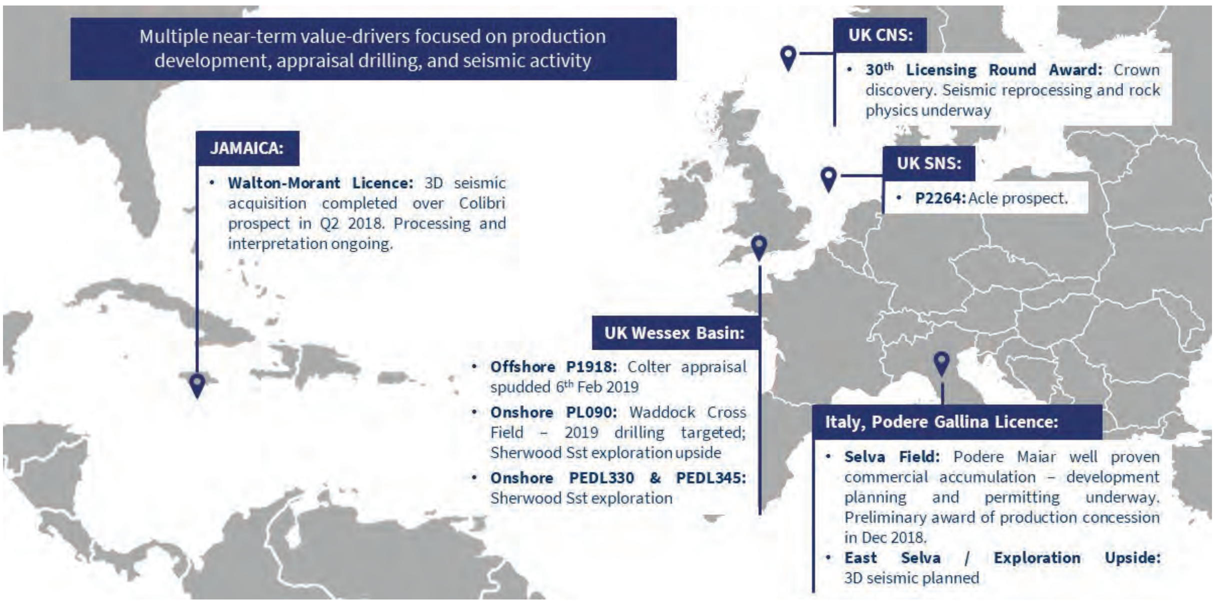
Country	*Licence*	*Operator/Administrator*	*UOG Interest*	*Status*
Italy	Podere Gallina Licence	Po Valley Operations Pty Ltd	20.00%	Infrastructure build 2019 Production from Podere Maiar well expected in 2020 Evaluation of exploration opportunities continuing
UK	PL090 (Waddock Cross)	Egdon Resources UK Limited	26.25%	Development well drilling targeted in 2019
UK	PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	18.95%	Seismic interpretation continuing
UK	P1918* (Colter)	Corallian Energy Limited	10.00%	Colter drill underway Results due in March
UK	PEDL 330	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing
UK	PEDL 345	Corallian Energy Limited	10.00%	Evaluation of exploration opportunities continuing
UK	P2264* (Acle)**	Swift Exploration Limited	24.00%	Evaluation of exploration opportunities continuing
UK	P2366* (Crown)	United Oil & Gas Plc	95.00%	Seismic reprocessing and rock physics underway ahead of firming up development plans
Jamaica	Walton-Morant*	Tullow Jamaica Limited	20%	Processing and interpretation of acquired 3D seismic – drill-or-drop decision by end of 2019

*Offshore

** UOG's interest in Licence P2264 (Acle) is subject to execution of a Farm-in Agreement. The initial term of the licence expires at the end of November 2019. However, the current operator, Swift, is committed to inform the Oil and Gas Authority ("OGA") by 28 February 2019 of the companies that have agreed a farm-in to the block that will result in the drilling of a firm well. OGA approval will be required to extend beyond this date. Given progress to date and the proximity of the deadline, it is considered reasonably likely that Swift will be forced to relinquish the block.

For further information on each project, please refer to paragraph 3.3 below.

Current Portfolio Overview



The Directors work closely with all Joint Venture Partners and attend the technical committee meetings and operational committee meetings for the Company's assets taking an active role in all technical and operational decisions including participation in the execution of the work programmes.

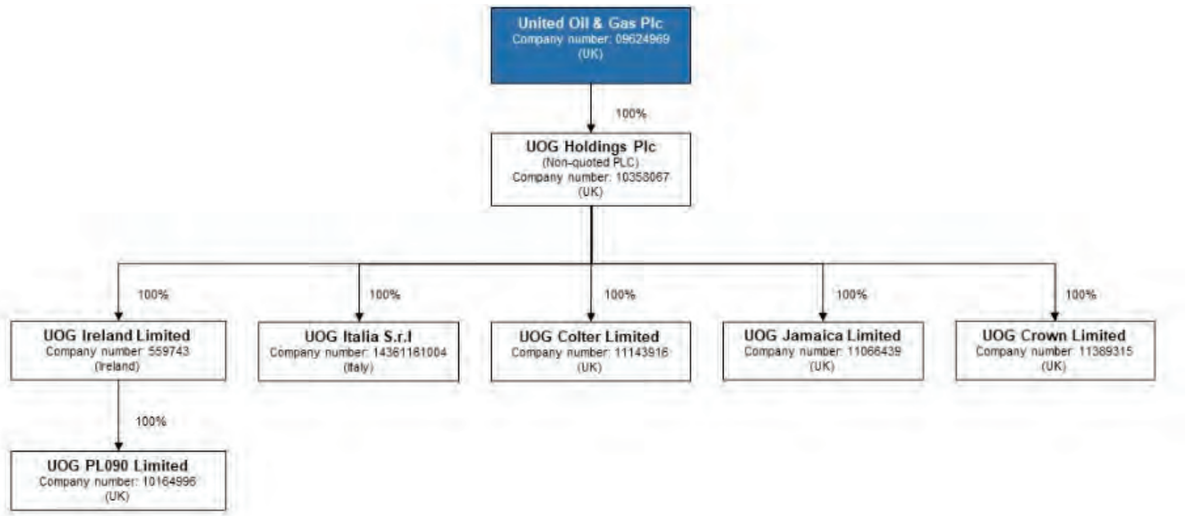
In Europe and the UK, the Company is aiming to create value through building actively managed interests in production, development, and low-risk exploration/appraisal oil and gas assets. The Company will also consider oil and gas assets in other regions on an opportunistic basis. Given the management team's previous experience, the focus will be on Caribbean, Latin America and Africa, where the Directors believe they will be able to access opportunities with low capex entry costs and potentially transformational upside.

The Directors are using their experience of actively working on the acquired equity assets to instigate activity and unlock the identified additional value in each prospect. In addition, the Directors have an extensive network of senior oil and gas executives which they use to access early divestment opportunities and avoid auctioned transactions.

3.2 ***Group Structure***

The Company acts as the ultimate holding company of the Group and has one wholly owned subsidiary, UOG Holdings Plc, which in turn has the following five wholly owned subsidiaries; UOG Ireland Limited, UOG Italia S.r.l., UOG Colter Limited, UOG Jamaica Limited and UOG Crown Limited. UOG Ireland has one wholly owned subsidiary, UOG PL090 Limited.

The current ownership structure is illustrated in the diagram below:



3.3 ***Projects***

3.3.1 ***Podere Gallina Project (Italy)***

Licence description

The Podere Gallina Licence is located in the Po Valley plain, and covers an area of 506 square kilometres. The currently shut-in Selva gas field lies within this licence area. This field, operated by ENI, the Italian oil and gas multinational, produced 83 Bcf over a 35 year period from 15 wells. Production ceased in 1984.

As a result of a farm-in agreement between Po Valley Operations Pty Ltd and UOG UK signed on 4 May 2017, UOG acquired a 20 per cent. working interest in the Podere Gallina Licence on funding 40 per cent. of the cost of the Podere Maiar appraisal well that was drilled in Q4 2017. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63 per cent. working interest in the licence. Prospex Oil and Gas plc hold the remaining 17 per cent. working interest. *(Source: CGG CPR paragraph 1.3)*

Table 1. Podere Gallina licence details

Operator	UOG Interest (%)	Status	Licence expiry date	Licence Area
PVO	20%	Exploration	3 February 2018*	506 km^2

** In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorization time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from 3 February 2018. The application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law. (Source: CGG CPR paragraph 1.3)*

Further information is set out in the Risk Factors in Part III of this Document.

Location

The Po Basin runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years. The Podere Gallina Licence is located approximately 10 km to the east of Bologna, and about 30 km from the coast in the Ferrara and Bologna provinces of the Emilia-Romagna region. *(Source: CGG CPR paragraph 1.1)*

Figure 1. Location map for Podere Gallina Licence *(Source: CGG CPR paragraph 1.1)*

Reserves and Resources

A summary of the resources associated with the "Selva Stratigraphic" redevelopment opportunity and the three prospects, both gross and net, in accordance with the 2007 Petroleum Resource Management System (PRMS) published by the SPE, are shown in the table below.

The volumes associated with the "Selva Stratigraphic" redevelopment opportunity have been updated since the previous CPR (April 2018), which incorporated the results of the Podere Maiar-1 well. Given that the PM-1 well had further de-risked progression towards a commercial development, in May 2018, an application was submitted for a Production Concession, allowing gas production to commence from the PM-1 well after tie-in to the gas network pipeline nearby. This application included a development plan, and subject to award of the Production Concession, which was granted preliminary approval by the Italian Government, the recoverable volumes can be classified as Reserves within the CPR.

As the submitted development plan is based solely on production from the PM-1 well, in the 1P and 2P cases, CGG have considered a situation in which the entire structure is not drained, leading to a reduction in numbers compared to the previously reported 1C and 2C Contingent Resources, which were not based on a specific development plan. However, the 3P Reserves remain unchanged from the previously reported 3C Contingent Resources, as the possibility remains that all of the mapped volumes could be drained by the existing PM-1 well. A clearer picture will emerge on this once there is production history from the well. *(Source: CGG CPR paragraph 1.4)*

Standard cubic metre (scm) and standard cubic foot (scf) are the most widely used units used in natural gas industry to represent an amount of natural gas. Given that in most Continental European countries, including Italy, natural gas is reported in scm, the CGG CPR has been prepared to those standards and figures the Table 3. Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG are presented in MMscm. However, given in the United Kingdom natural gas is reported in scf, figures in Table 3. have been converted from MMscm into bcf (using conversion ratio 1 scm = 35.3147 scf) and these are presented in Table 2. below.

Table 2. Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG in bcf

Selva Stratigraphic Trap	Gross (bcf)			20% Net attributable (bcf)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	1.70	4.56	7.38	0.35	0.92	1.48	PVO
C2 Sand	2.44	8.83	22.50	0.49	1.77	4.48	
Total	**4.13**	**13.38**	**29.88**	**0.81**	**2.68**	**5.97**	

Table 3. Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG

Selva Stratigraphic Trap	Gross (MMscm)			20% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	10	26	42	PVO
C2 Sand	69	250	637	14	50	127	
Total	**117**	**379**	**846**	**23**	**76**	**169**	

** The net attributable may not add due to rounding error.*

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project for a 100 per cent. field interest and respective UOG net interest. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change. *(Source: CGG CPR paragraph 1.4)*

Table 4. Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	2.0	5.5	9.2	PVO
Low	7.6	21.3	36.2	1.5	4.3	7.2	
High	12.7	33.5	56.0	2.5	6.7	11.2	

CGG's gas price assumption follows the forward Italian PSV spot gas price curve until 2025, and thereafter escalates at 2 per cent. per year. Low and high price decks have been taken as +/- 15 per cent. for 2019 and 2020, and +/-20 per cent. for 2021 onwards. *(Source: CGG CPR paragraph 1.4)*

Work Programme

The Podere Maiar 1 well on the Selva structure was drilled in late December 2017 and tested in early 2018. The well found a significant gas accumulation that flowed strongly on test, and which is clearly commercial. Following these results, the operator of the Podere Gallina Licence, PVO, is progressing with an application to the Italian Ministry for a Production Concession submitted in May 2018. This mining title will be awarded by Ministry after i) the competent Ministry's commission positive opinion, ii) the positive environment assessment and, iii) the resolution by the Region Emilia Romagna granting the agreement with the Government. As announced in January 2019, the application has been granted preliminary approval as the competent Ministry's commission issued its positive opinion. The award of the Production Concession will enable the Joint Venture Partners to proceed with the development and establish production. The gross estimated development costs are €2.339m (€0.47m net to UOG).

The results of the Podere Maiar-1 well also highlighted the significant exploration potential in the Podere Gallina Licence, and helped to de-risk the East Selva prospect. To better define this prospectivity, a 3D seismic survey has been proposed. The gross costs associated with this seismic acquisition are currently estimated at €3m (€0.6m net to UOG).

3.3.2 *Waddock Cross and Broadmayne Projects (PL090 Licence, UK)*

Licence description

UOG acquired its interest in the PL090 Licence through the acquisition of the assets of First Oil's subsidiaries in August 2016. UOG holds a 26.25 per cent. working interest in the Waddock Cross field area (approximately 19km^2) and a working interest of 18.9541 per cent. in the reminder of the PL090 Licence (approximately 183km^2). Both areas are operated by Egdon Resources UK Limited ("Egdon") and expire on 31 March 2024.There are no outstanding work commitments on the PL090 Licence. *(Source: ERCE CPR, Part 1)*

Table 5. Summary of UOG's PL090 Licence interests

License block	Operator / Administrato	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19 km^2	
		UOG PL090 Limited	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	183 km^2	
		UOG PL090 Limited	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				

3.3.2.1 ***Waddock Cross Project***

Location

The Waddock Cross field is located in Licence PL090 and is operated by Edgon Resources UK Limited. The licence is located within the Wessex Basin in the county of Dorset, onshore UK, to the west of the Wytch Farm oil field (Figure 2). *(Source: ERCE CPR para 2.1.1)*

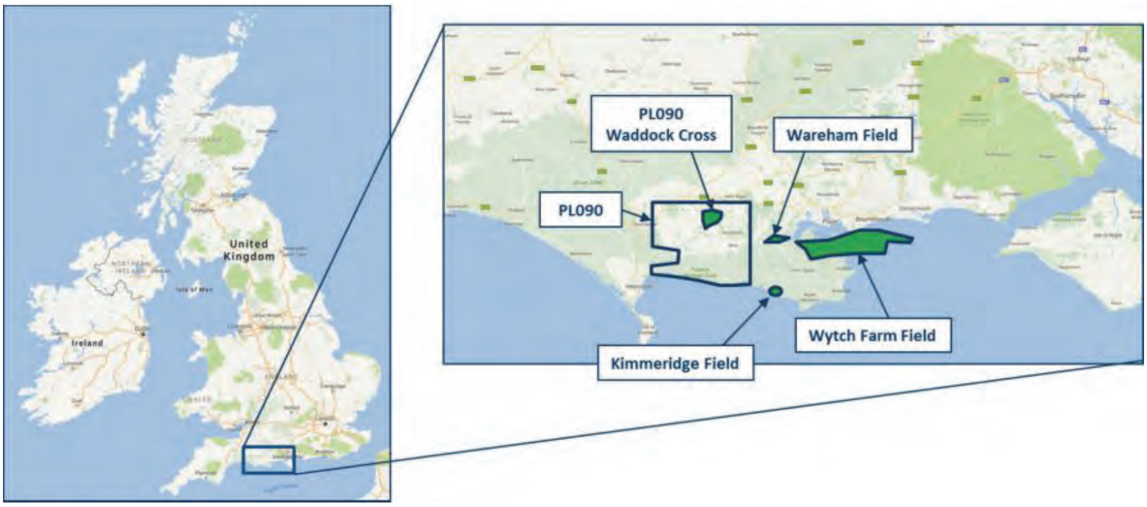


Figure 2. PL090 Licence Location and Neighbouring Oil Fields *(Source: ERCE CPR para 2.1.1)*

Waddock Cross is located in rural farmland close to woodlands approximately 11.5 kms east of Dorchester and 21.6 km west of Poole. The Grid Reference (UK National Grid) for the site is SY805912 and the nearest farm has the post code DT2 8QY. When the field was previously in production in 2013/14, oil was exported via road tanker to Holybourne Oil Terminal in Hampshire, power was supplied via mains electricity, and water was reinjected through the WX-2 well.

Neighbouring oil fields include the Wareham and Wytch Farm oil fields. Wytch Farm field produces oil predominantly from the Triassic Sherwood Sandstone reservoirs, with subordinate production from the younger Jurassic Bridport Sandstone reservoir. The Wareham field also produces oil from the Bridport Sandstone reservoir. *(Source: ERCE CPR para 2.1.1)*

Contingent Resources

According to the Competent Persons Report produced by ERC Equipoise Ltd ("ERCE") titled "Evaluation of certain Contingent and Prospective Resources of United Oil & Gas Plc", which is included in Part VIII of the Document, Waddock Cross field contains oil within the Jurassic Bridport Sandstone reservoir, and has historically undergone oil production, curtailed due to a high water cut. The field is currently shut in. The operator, Egdon Resources UK Limited ("Egdon"), is investigating the restoration of production, via the drilling of one or more horizontal wells in a structurally higher area of the field. A revised reprocessing of the existing 3D seismic dataset that covers the Waddock Cross field has recently been completed; this latest reprocessing focused on addressing the apparent statics issues. The new PSTM and PSDM seismic volumes have been used to update the Waddock Cross structural interpretation and associated models of top reservoir depth structure, which are being assessed to determine the optimal location for the development wells. ERCE has reviewed the recently reprocessed time and depth seismic data and has adopted the new time and depth seismic data as the basis for seismic interpretation. ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. Development is contingent on the preparation and the commitment to a commercial development plan. UOG estimates the chance of development ("Pd") to be 75 per cent. which would likely involve the drilling of two new wells with any water being reinjected. The oil would be evacuated by road. ERCE has reviewed the estimated chance of development (Pd) and consider this to be a fair assessment. There are no identified Reserves. *(Source: ERCE CPR Executive Summary)*

ERCE's estimates of the unrisked oil Contingent Resources in the Waddock Cross field, both gross and net to UOG, are shown in Table 6 below. ERCE has reviewed UOG's assessment of chance of development and feel 75 per cent. is an appropriate estimation.

Table 6. Unrisked Oil Contingent Resources of the Waddock Cross Field, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%

Notes:

(1) "Gross Contingent Resources" are 100 per cent. of the volumes estimated to be recoverable from the field without any economic cut-off being applied.

(2) "Net Contingent Resources" are UOG's working interest fraction of the gross contingent resources.

(3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.

(4) The volumes reported here are unrisked in that they have not been multiplied by the chance of development (Pd).

(5) In accordance with SPE PRMS.

(Source: ERCE CPR para 1.2.1.1)

Work Programme

Reprocessing of the Waddock Cross 3D survey was completed in August 2018. Work is now being completed by the operator, Egdon, to model reservoir performance and well-costing. Based on this work a final decision on the well-design is expected in early 2019, at which point the work programme and costs associated with drilling at Waddock Cross field will be determined. UOG anticipate drilling in 2019, with a gross cost in the region of £1-1.5m (£260-£400k net to UOG).

3.3.2.2 ***Broadmayne Project***

Location

The Broadmayne prospect is situated to the southwest of the Waddock Cross field, and is mapped as straddling the PL090 license block at Sherwood Sandstone level (Figure 3).

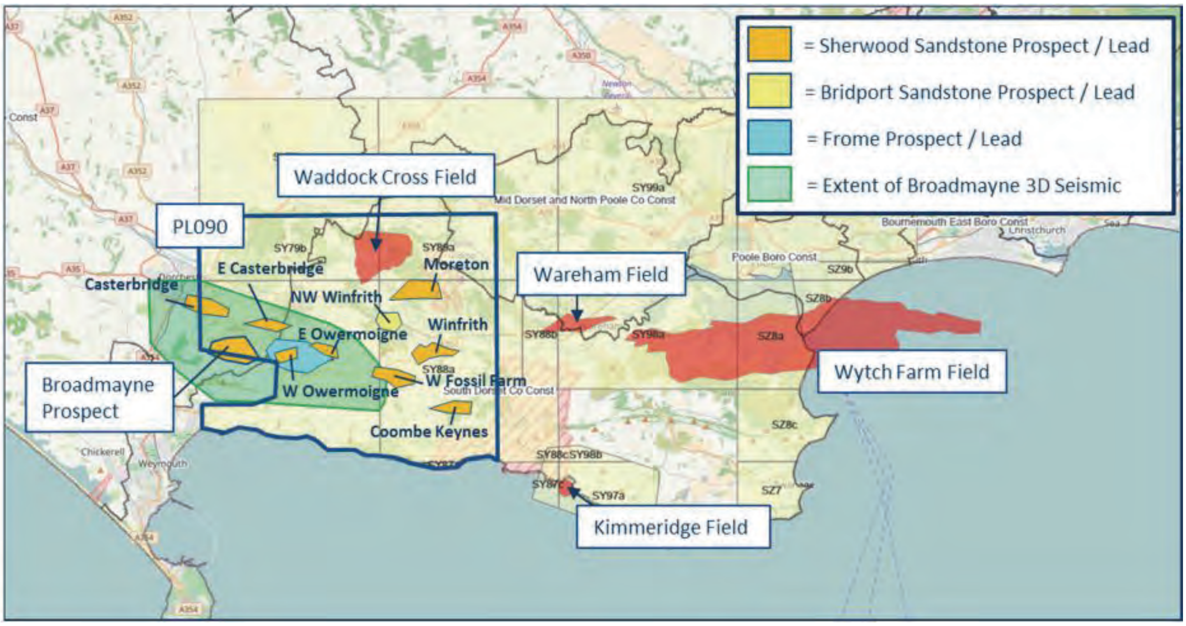


Figure 3. Locations of Wessex Basin leads

(Source – Oil & Gas Authority) (Source: ERCE CPR para 3.1.1)

Prospective Resources

The PL090 partnership is maturing prospectivity within the greater licence area, and identifies a number of undrilled exploration prospects and leads. The licence is located in Wessex Basin onshore UK, to the west of the Wytch Farm oil field. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil Prospective Resources and Geological Change of Success for the Broadmayne prospect, which is currently the most mature. *(Source: ERCE CPR Executive Summary)*

The licence contains two 3D surveys; the Waddock Cross 3D seismic survey acquired in 2004 and the larger Broadmayne 3D survey, which was acquired in 2013 and lies to the southwest of Waddock Cross. The data have been reprocessed a number of times and the third vintage of reprocessing has been used by UOG and partners in the mapping and identification of leads and prospects (Figure 3), including the Broadmayne prospect, which is currently the most mature and to which ERCE has restricted its assessment of Prospective Resources. The data have recently been reprocessed for a fourth time and provisional interpretation performed by UOG over the Broadmayne prospect supports historical mapping and the presence of dip and fault-closure. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report. It is anticipated that mapping and prospect maturation will continue using the results of this recent reprocessing. *(Source: ERCE CPR para 3.1.1)*

ERCE's estimates of the gross unrisked oil Prospective Resources in Broadmayne and the net unrisked and risked Prospective Resources attributable to UOG based on the mapped area of the prospect in Licence PL090 are shown in Table 7.

Table 7. STOIIP, Oil Prospective Resources and Geological Chance of Success for the Broadmayne Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Mid	High	Mean	1U	2U	3U	Mean	
Broadmayne	Egdon Resources UK Limited	5.00	11.10	24.50	13.40	1.50	3.30	7.40	4.00	18.95%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Mid**	**High**	**Mean**
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

*Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95 per cent.) and by the proportion of resources which ERCE estimates to fall within the PL090 block boundary (50 per cent.).

Notes:

(1) Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.

(2) "Gross Unrisked Prospective Resources" are 100 per cent. of the volumes estimated to be recoverable from an accumulation

(3) "Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources

(4) "Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).

(5) The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.

(6) Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).

(Source: ERCE CPR para 1.2.2.1)

ERCE has adopted a four component risk matrix in their assessment of Geological Chance of Success (COS) for the Broadmayne Prospect, comprising source, reservoir (presence and efficacy), trap and seal.

ERCE perceives there to be no material risk associated with reservoir presence, efficacy and top seal, based on the results of the offset wells. The dominant risk factors for the Broadmayne prospect are source/migration and trap integrity.

Source encompasses both the presence of source rock material and migration. The presence of producing oil fields in the area confirms the presence of source rocks. Success for Broadmayne relies upon a migration pathway existing to the west of the main source area of the basin into Licence PL090.

Trap embraces all the components that define the competency of the closure. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

ERCE assessment of the COS for the Broadmayne prospect is 30 per cent., as presented in Table 8.

Table 8. Broadmayne Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Sherwood	0.50	1.00	0.60	1.00	0.30

(Source: ERCE CPR para 3.1.4)

Work Programme

Improved seismic reprocessing was completed by Dayboro Geophysical at the end of 2017. Initial interpretation of this data has been encouraging, but more interpretation work is needed prior to finalising Broadmayne volumes, and a decision being made on the best way forward for the PL090 joint venturers. Although work is continuing, there are currently no plans in place for activity involving capital expenditure on the Broadmayne exploration prospect.

3.3.3 ***Colter East and West Projects (P1918 Licence, UK)***

Licence description

In January 2018, UOG completed a farm-in deal to acquire 10 per cent. of the P1918 Licence (operated by Corallian Energy Limited ("Corallian")). The P1918 Licence interests are summarised in Table 9.

Table 9. Summary of UOG's P1918 Licence interest

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
P1918 (Colter)	Corallian Energy Limited	Corallian Energy Limited	49.00%	Extant	01/02/2020 01/02/2021 (Second Term) 01/02/2038 (Licence End Date)	36.2 km^2	
		UOG Colter Ltd	10.00%				
		Corfe Energy Limited	25.00%				
		Baron Oil	8%				
		Resolute Oil & Gas	8%				

Location

The Colter discovery is located in licence P1918 and is operated by Corallian. The licence is located offshore southern UK, south of Wytch Farm oil field (Figure 4).

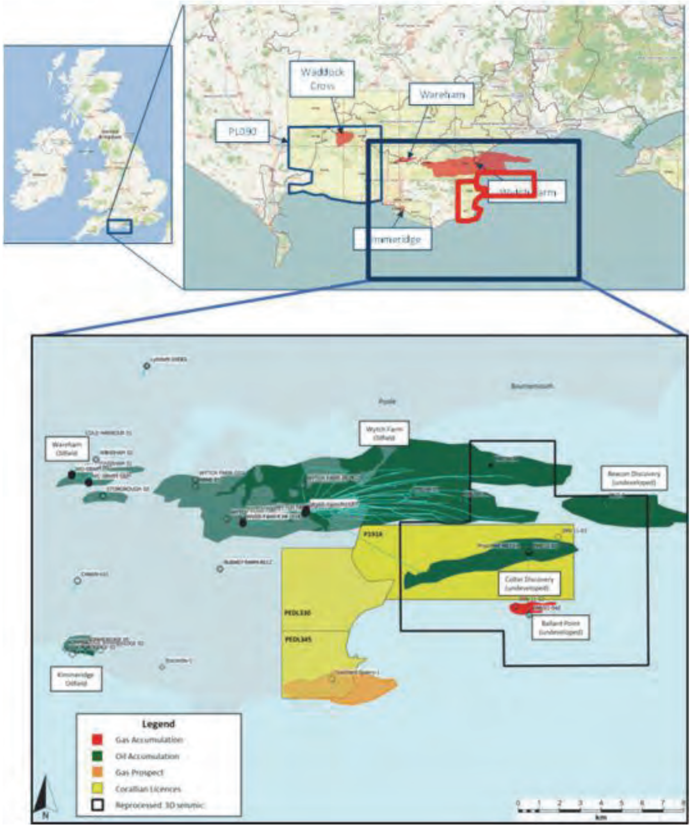


Figure 4. Colter Field Location Map

(Source: ERCE CPR para 2.2.1)

Interpretation of the top reservoir structure is challenging and there is uncertainty associated with both the presence and location of a northwest to southeast trending fault that segments the discovery into Colter East and Colter West. Reprocessing of the 3D seismic survey covering the Colter discovery was completed in April 2018. However, the new seismic image has not changed the current interpretation of the fault nor the associated uncertainty in its position. *(Source: ERCE CPR Executive Summary)*

Colter East Project: Contingent Resources

Well 98/11-3 penetrates the eastern segment of the discovery (Colter East). The well was tested and flowed 8.5 bbl of oil to surface together with water. Plans to drill an up-dip appraisal well in Q1 2019 are well underway. The operator Corallian has been issued the relevant consents from OPRED, performed a site survey and contracted the Ensco 72 jack-up drilling unit to drill the well. Drilling commenced at 10:10 hrs on 6 February 2019 and is expected to take approximately 3 weeks to reach a planned total depth of 1,830 meters. ERCE therefore attributes unrisked Contingent Resources (sub-classification Development Pending) to Colter East as shown in Table 10. The contingencies include the success of the updip appraisal well and the commitment to, and preparation of a commercial development plan. ERCE has reviewed UOG's assessment of chance of development and feel 75 per cent. is an appropriate estimation.

Table 10. Unrisked Oil Contingent Resources of Colter East, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL1918	Colter East	Corallian Energy Limited	1.68	4.08	10.12	10.00%	0.17	0.41	1.01	75%

Notes:

(1) "Gross Contingent Resources" are 100 per cent. of the volumes estimated to be recoverable from the field without any economic cut-off being applied.

(2) "Net Contingent Resources" are UOG's working interest fraction of the gross contingent resources.

(3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.

(4) The volumes reported here are unrisked in that they have not been multiplied by the chance of development (Pd).

(5) In accordance with SPE PRMS.

(Source: ERCE CPR para 1.2.1.2)

Colter West Project: Prospective Resources

The Colter West prospect is separated from Colter East by a northwest to southeast trending fault. Colter West is penetrated by Well L98/06-M18Z, known as Old Harry, which was drilled in 2000 to the west of Well 98/11-3. Old Harry appeared to encounter some thin hydrocarbon-bearing sands in the Sherwood (presumed to be oil bearing), based on log responses. No tests were undertaken. ERCE therefore assigns Prospective Resources to Colter West updip of the Old Harry well. ERCE's estimates of the gross unrisked oil Prospective Resources and Geological Chance of Success for Colter West and the net unrisked and risked Prospective Resources attributable to UOG in the P1918 Licence are shown in Table 11. ERCE has reviewed UOG's assessment and believe this to be a fair appraisal.

Table 11. STOIIP, Oil Prospective Resources and Geological Change of Success for the Colter West Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Mid	High	Mean	1U	2U	3U	Mean	
Colter West	Corallian Energy Limited	15	38	95	49	4	11	29	15	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Mid**	**High**	**Mean**
Colter West	Corallian Energy Limited	0.43	1.13	2.87	1.47	50%	0.22	0.56	1.44	0.74

*Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the P1918 Licence (10.00 per cent.).

Notes:

(1) Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.

(2) "Gross Unrisked Prospective Resources" are 100 per cent. of the volumes estimated to be recoverable from an accumulation

(3) "Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources

(4) "Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).

(5) The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.

(6) Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).

(Source: ERCE CPR para 1.2.2.2)

ERCE perceives there to be no material risk associated with reservoir presence, efficacy, top seal and source and migration based on the results of the offset wells. The dominant risk factor for the Colter West prospect is trap integrity. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

ERCE's assessment of the COS for the Colter prospect is 45 per cent., as presented in Table 12.

Table 12. Colter West Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Colter	1	1	0.5	1	0.50

(Source: ERCE CPR para 3.1.4)

Work Programme

Within the forecast period UOG is committed to funding 13.33 per cent. of the drilling costs for the offshore Colter exploration well (98/11a-5) in the P1918 Licence. Drilling commenced at 10:10 hrs on 6 February

2019 and is expected to take approximately 3 weeks to reach a planned total depth of 1,830 meters. Total well costs are expected to be £7.5m of which UOG have estimated their share to be £1m.

The Company also holds interests in UK onshore licences PEDL330 and PEDL345 with the same 10 per cent. equity as Licence P1918. However, evaluation is at an early stage and no leads have yet been identified; these licences have not therefore been included in the ERCE CPR and there is no forecast spend in relation to the PEDL330 Licence and PEDL 45 Licence in the forecast period.

3.3.4 *Crown Project (P2366 Licence, UK)*

Licence description

The Crown discovery, in which UOG has a 95 per cent. interest (Table 13) and is licence administrator, is located in licence P2366 and straddles Blocks 15/18d and 15/19b located at the north west margin of the Witch Ground Graben, offshore the United Kingdom.

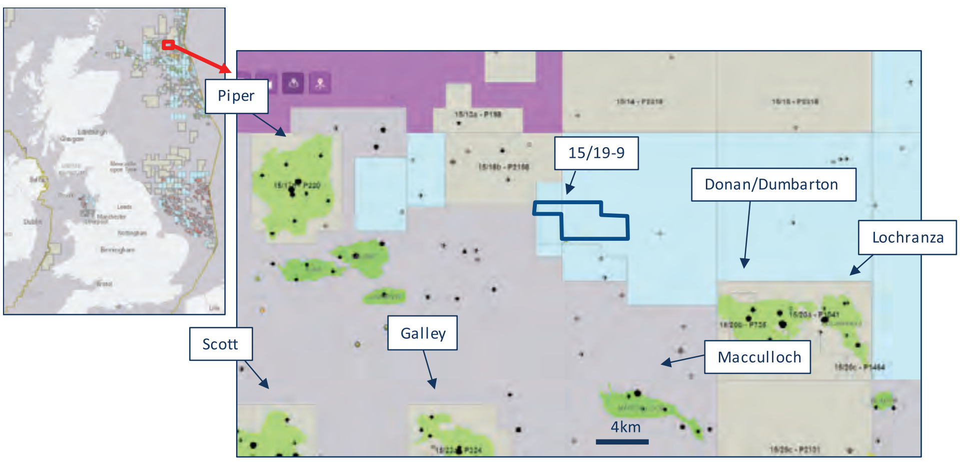
(Source: ERCE CPR Executive Summary)

Table 13. Summary of UOG's P2366 Licence interest

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
P2366 (Crown)	United Oil & Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/9/2021 (Phase A) 30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)	13.6 km2	Phase A work commitments include the reprocessing of 40km2 of 3D seismic and an associated Rock Physics study. Phase C will start on the condition that there is a firm commitment to drilling a well.
		Swift Exploration Limited	5.00%				

Location

The Crown discovery is located in Block 15/19 offshore UK. UOG was awarded a 95 per cent. interest in the block in August 2018 as part of the UK offshore 30th Licensing Round. The licence is located offshore UK at the northwest margin of the Witch Ground Graben (Figure 5).



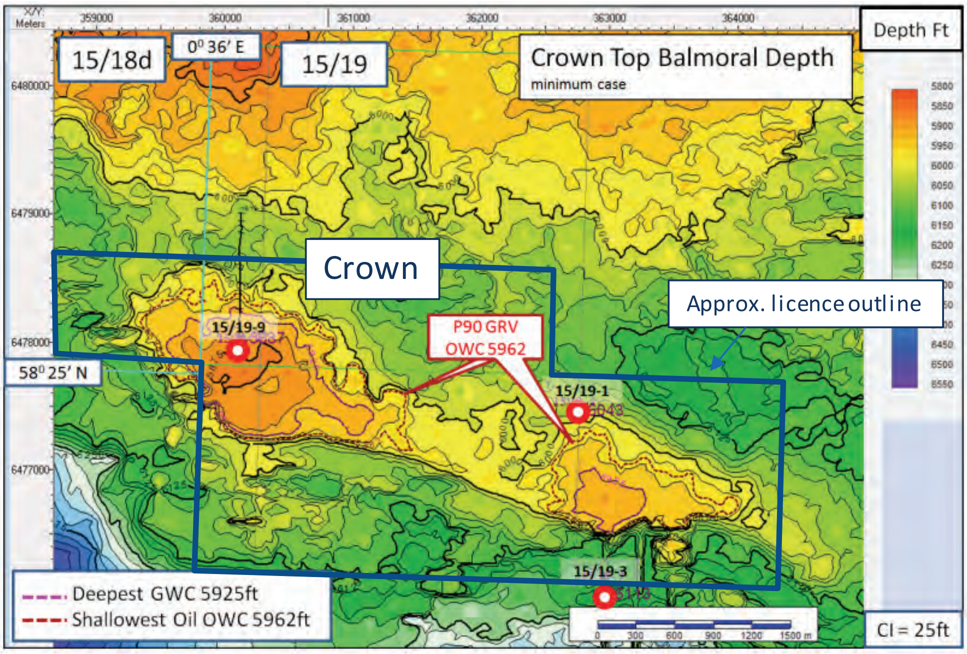


Figure 5. Crown Field Location Map
(Source: ERCE CPR para 2.3.1)

Contingent Resources

Crown was discovered by Well 15/19-9 in 1998. The well encountered in excess of 200 ft of good quality Balmoral Sandstone reservoir of Palaeocene age. The discovery has an oil rim of thickness between 35 and 55 ft overlain by gas and underlain by water-bearing sandstone. Wireline log oil saturations of up to 80 per cent. are encountered. ERCE attributes Contingent Resources (sub-classification Development Unclarified) to Crown. Development is contingent on the preparation and the commitment to a commercial development plan. UOG estimates the chance of development to be 40 per cent. ERCE has reviewed the estimated Pd and considers this to be an appropriate assessment. *(Source: ERCE CPR Executive Summary)*

ERCE's STOIIP and Contingent Resources (sub-classification Development Unclarified) estimates are presented in Table 14. ERCE has reviewed UOG's assessment of chance of development and feel 40 per cent. is an appropriate estimation.

Table 14. Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	40%

Notes:

(1) "Gross Contingent Resources" are 100 per cent. of the volumes estimated to be recoverable from the field without any economic cut-off being applied.

(2) "Net Contingent Resources" are UOG's working interest fraction of the gross contingent resources.

(3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.

(4) The volumes reported here are unrisked in that they have not been multiplied by the chance of development (Pd).

(5) In accordance with SPE PRMS.

(6) Crown carries a 40 per cent. chance of development.

(Source: ERCE CPR para 2.3.7)

Work Programme

Seismic reprocessing and rock physics studies are part of the work commitments designed to help delineate and de-risk the Crown discovery. These are currently underway, and are due to be completed in Q2 2019. This will be used to further constrain the volumetric range and feed into development planning ahead of any commitment to drill. As well as working up the field technically, UOG will also consider all options that will optimize progress towards development, including potential farm-out options.

3.3.5 ***Acle Project (P2264 Licence, UK)***

Licence description

In January 2018, UOG agreed an option with Swift Exploration Limited and Stelinmatvic Industries Ltd to farm-in to Block 49/29c of Licence P2264 for a 24 per cent. interest, executable upon a drilling commitment being made on the Acle prospect. The option is valid until expiry of the licence, which will be no earlier than 28 February 2019.The licence interests are summarised in Table 15.

Table 15. Summary of UOG's P2264 Licence interest

Licence block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
P2264* (Acle)	Swift Exploration Limited	Swift Exploration Limited	38.00%	Extant	28/02/2019 (Farm-in notification to OGA) 30/11/2019 (Initial Term) 30/11/2022 (Second Term) 30/11/2040 (Anticipated End Date)	29.01km2	An extension to the deed of variation granted on the 27th November 2018 has been awarded extending the date by which a legal binding farm-in agreement must be executed to 28 Feb 2019, and the expiry of the initial term of the licence (30 Nov 2019)
		Stelinmatvic Industries Ltd	38.00%				
		United Oil & Gas Plc	24.00%				

* UOG's interest in Licence P2264 is subject to execution of a Farm-in Agreement. The initial term of the licence expires at the end of November 2019. However the current operator, Swift, is committed to inform the Oil and Gas Authority ("OGA") by 28th February 2019 of the companies that have agreed a farm-in to the block that will result in the drilling of a firm well. OGA approval will be required to extend beyond this date. If insufficient progress has been made by this date, there is a possibility that Swift will be forced to relinquish the block.

Location

Licence P2264 is located offshore UK in the Southern North Sea (SNS), Block 49/29c. The block is surrounded by several gas fields (Figure 6), including Gawain to the north, and North Davy due east. The licence is covered by a high-quality 3D seismic survey and numerous 2D seismic lines.

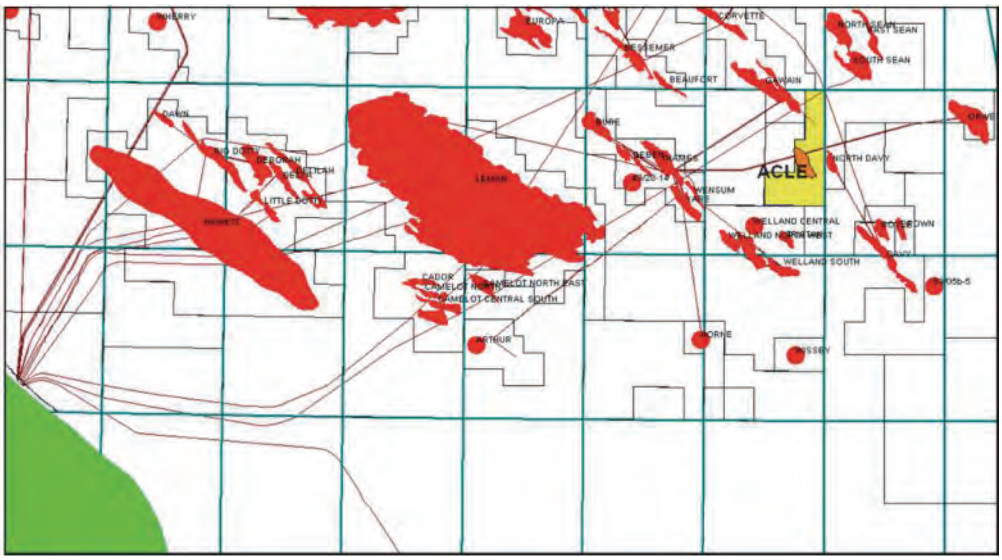


Figure 6. Location Map showing P2264 licence *(Source: ERCE CPR para 3.2.1)*

Prospective Resources

The Rotliegend play fairway in the region is well established, comprising aeolian Rotliegend Leman Sandstone reservoir, charged by underlying gas-prone Carboniferous coal measures. Top seal is provided by regional Zechstein evaporites. Tilted fault blocks are typically the dominant trapping mechanism in the Rotliegend play fairway in the SNS. *(Source: ERCE CPR para 3.2.1)*

ERCE interpret the Acle prospect as a tilted fault-block with lateral seal to the south defining the spill point for the structure.

A summary of ERCE's estimates of undiscovered GIIP and gas Prospective Resources is presented in Table 16.

Table 16. Acle Prospect – GIIP and Gas Prospective Resources

Prospect	Operator / Administrator	GIIP (Bcf)				Gross Unrisked Prospective Resources (Bcf)				*Working Interest
		Low	Mid	High	Mean	Low	Mid	High	Mean	
Acle	Swift Exploration Limited	57	132	301	16	42	99	226		24%

Prospect	Operator / Administrator	Net Unrisked Prospective Resources				COS	Net Risked Prospective Resources (Bcf)			
		1U	2U	3U	Mean		Low	Mid	High	Mean
Acle	Swift Exploration Limited	10	24	54	29	43%		4.4	10.2	23.3

*Net Unrisked and Risked Prospective Resources assume execution of the Farm-In Option to Licence P2264 (24.00 per cent.)

Notes:

(1) Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.

(2) "Gross Unrisked Prospective Resources" are 100 per cent. of the volumes estimated to be recoverable from an accumulation

(3) "Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources

(4) "Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).

(5) The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.

(6) Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).

ERCE perceives there to be low risk associated with source, reservoir presence, efficacy and top seal, based on the results of the offset wells, and density of surrounding gas fields. The dominant risk factor for the Acle prospect is the trap integrity. Trap embraces all the components that define the competency of the closure. The prospect relies on the presence of a laterally sealing fault to the south, and there is significant uncertainty on the associated position, throw and fault seal potential. *(Source: ERCE CPR para 3.2.3)*

Work Programme

On 24 January 2018 UOG announced a no-cost option agreement to farm into offshore Block 49/29c UK Licence P2264 containing the Acle prospect. The option is for UOG to farm-in for a 24 per cent. interest of this licence, in return for paying 30 per cent. of the exploration costs of the first well, plus £20k to each partner on exercise of the option. The initial term of the licence expires at the end of November 2019. However, the current operator, Swift, is committed to inform OGA by 28th February 2019 of the companies that have agreed a farm-into the block that will result in the drilling of a firm well. OGA approval will be required to extend beyond this date. Given progress to date and the proximity of the deadline, it is considered reasonably likely that Swift will be forced to relinquish the block.

3.3.6 ***Colibri Project (Walton-Morant Licence, Jamaica)***

Licence description

The Walton-Morant licence area is situated offshore Jamaica and covers 32,065 km^2 (Figure 7.). The Production Sharing Agreement (PSA) became effective on 1 November 2014 and Tullow Jamaica is the operator. UOG has signed an agreement with Tullow Jamaica to farm-in to the Walton-Morant Licence at a 20 per cent. equity interest. This will involve paying a 20 per cent. share of costs. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data which was designed to concentrate on the Colibri prospect. Since the acquisition the data have been reprocessed and a number of 3D seismic volumes and derived attributes have been generated. *(Source: ERCE CPR 3.3.1).*

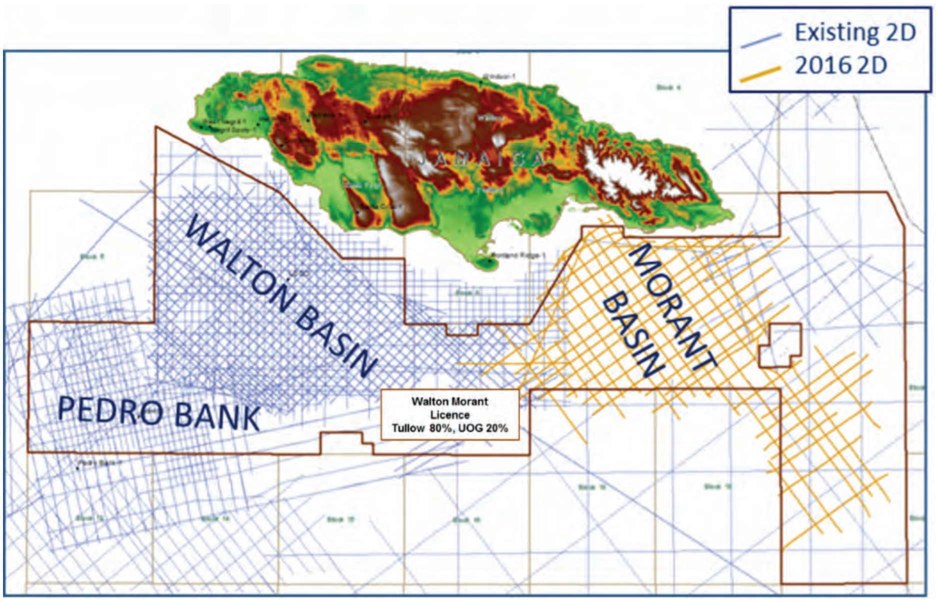


Figure 7. The Walton-Morant Licence, offshore Jamaica *(Source: ERCE CPR 3.3.1)*

The Walton-Morant Licence interests are summarised in Table 17.

Table 17. Summary of UOG Licence Interests

Licence block		Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
Walton-Morant (Colibri)	Tullow Jamaica Limited	Tullow Jamaica Limited	80.00%	Extant	2024	32,065km^2	60% relinquishment, drill or drop 2019
		UOG Jamaica Limited	20.00%				

Location

The licence contains the Pedro Bank carbonate platform and the Walton and Morant Basins, of which the Walton Basin is the primary exploration focus as it contains siliciclastic reservoirs located within a thermally mature kitchen area. *(Source: ERCE CPR 3.3.1)*

The Colibri prospect is situated in the Walton Basin in water depths of approximately 750 m (Figure 8). The prospect is a well-defined fault-bounded structure with onlap and drape. The basinal position suggests overlying pelagic shales and marls will likely form a seal. The 3D seismic data demonstrate that some faulting propagates to seabed, implying the possibility of trap breach. The prospect is also well positioned to receive charge from surrounding Eocene and/or Cretaceous kitchens, and is located close to the Blower Rock oil seep. The improved imaging provided by the 3D seismic data provides positive evidence for migration pathways and fluid movement through the Walton Basin. The area has also been interpreted by Tullow Jamaica to sit within the Guy's Hill Formation depositional fairway.

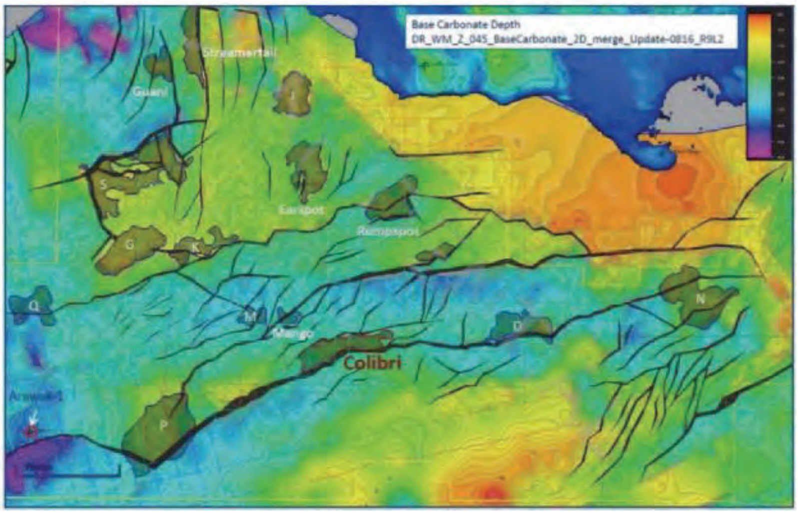


Figure 8. Location of Colibri and associated leads in the Walton Basin *(Source: ERCE CPR 3.3.2)*

Prospective Resources

The principal offshore exploration target identified by the operator, Tullow Jamaica, is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20 per cent. porosity at outcrop. The Guy's Hill formation is a fluvio-deltaic-shallow marine succession of up to 320 m gross thickness onshore, and is capped by regional shales and marls. Well Arawak-1 is the nearest offshore penetration of the Guy's Hill formation located approximately 70 km to the west of the Calibri prospect. Tullow has identified a number of undrilled prospects and leads, of which the Colibri prospect is currently the most mature. The prospect lies in water depths of approximately 750 m and is a fault-bounded structure prognosed to contain Guy's Hill formation reservoir. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data, including coverage of the Colibri prospect. These data have been reprocessed, and a number of stacked volumes and derived attributes have been generated. These volumes form the basis for the interpretation and ERCE's updated estimation of Prospective Resources. *(Source: ERCE CPR Executive Summary)*

A summary of ERCE's estimates of undiscovered STOIIP and oil Prospective Resources is presented in Table 18.

Table 18: Colibri Prospect – STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Mid	High	Mean	1U	2U	3U	Mean	
Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Mid**	**High**	**Mean**
Colibri	Tullow Jamaica Ltd	6	26	103	46	20%	1.19	5.00	20.08	8.97

*Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the Walton-Morant Licence (20.00 per cent.)

ERCE assessment of the risk for the Colibri play is 54 per cent., with the prospect risk at 36 per cent., leading to a Geological chance of success as 20 per cent. The recently acquired 3D seismic data shows positive evidence of fluid movement and hydrocarbon presence in the basin and ERCE have therefore reduced the risk associated with play source and prospect migration since the last assessment. The dominant prospect risk is reservoir efficacy and presence, given the sparsity of wells and uncertain reservoir distribution in the basin. *(Source: ERCE CPR 3.3.3)*

Work Programme

In November 2017 UOG signed an agreement with Tullow Jamaica to farm-in to the Walton-Morant licence at a 20 per cent. equity interest. In May 2018, the acquisition of 2,250km^2 of 3D seismic data was successfully completed. This was the first ever 3D survey completed in Jamaica, and was focussed on the high-graded Colibri lead. This data is currently being processed and interpreted ahead of a JV farm-down effort. As well as confirming the presence of a sizeable prospect at Colibri, a number of additional leads and prospects have also been identified on the data. A drill-or-drop decision is required by end-2019, and following a successful farm-down, an exploration well could be drilled in 2020.

4. Joint Venture Partners

As at the date of this Document, the Group has the following joint venture partners in respect of its current portfolio of assets:

Egdon Resources U.K. Limited

Egdon Resources U.K. Limited is a company incorporated in England and Wales on 26 August 1997 under the UK Companies Act 1985 with company number 03424561, which operates oil-producing assets and also offers oil well drilling services. Egdon is a subsidiary of Egdon Resources plc, an established UK-based exploration and production company listed on AIM whose primary focus is on onshore exploration and production in the hydrocarbon-producing basins of the UK.

Po Valley Operations Pty Ltd

Po Valley Operations Pty Limited is a company incorporated on 10 July 1998 in Australia with ALN D83 354 269 that holds the Podere Gallina Licence. Po Valley Operations Pty Ltd is a subsidiary company of Po Valley Energy Limited, an emerging oil & gas exploration and development company listed on ASX which has an expanding portfolio of hydrocarbon assets in northern Italy.

Corallian Energy Limited

Corallian Energy Limited is a company incorporated in England and Wales on 21 October 2015 under the Act with company number 09835991. Corallian is a private UK oil and gas exploration and appraisal company which holds interests in petroleum licences in the UK.

Tullow Jamaica Limited

Tullow Jamaica Limited is a company incorporated in England and Wales on 5 August 2014 under the Act with company number 09162755. The principal activity of Tullow Jamaica is to acquire and hold interests in exploration licences in Jamaica. The ultimate holding company of Tullow Jamaica is Tullow Oil plc, an independent oil and gas exploration and production group listed on the Main Market, with a focus on finding and monetising oil in Africa and South America.

Swift Exploration Limited

Swift Exploration Limited is a company incorporated in England and Wales on 16 April 2003 under the UK Companies Act 1985 with company number 4736197. Swift is a private oil and gas exploration company which focuses on developing exploration and production opportunities in the Southern North Sea and the adjacent East Midlands UK onshore province for farm-out/sale.

Stelinmatvic Industries Ltd

Stelinmatvic Industries Ltd is a company incorporated in England and Wales on 10 May 2004 under the UK Companies Act 1985 with company number 5123578.

5. Company objective, strategy and prospects

The Company's strategy is to build a portfolio of production, development and low-risk appraisal/exploration oil and gas assets in Europe, whilst remaining alert for exceptional growth opportunities on a global basis – primarily in Caribbean, Latin America and Africa.

The Directors have a proven track record of successfully evaluating and recommending farm-in deals and will continue to develop the current assets seeking to unlock the identified and additional value whilst remaining alert for exceptional growth opportunities on a global basis to acquire assets in which full value is not currently being realised. The Board is constantly looking at potential acquisition, joint venture or other business opportunities which may achieve capital growth for the Company.

The Company has a dual-focused portfolio of low risk, late stage appraisal/development projects in Europe and high-impact exploration plays in the Caribbean, Latin America, and Africa.

In Europe, the Group's primary focus is to create value through active management of a portfolio of production, development, and low-risk exploration/appraisal assets where the management team's experience can be utilised. Assets in other countries and regions might be considered on an opportunist basis and given the Directors' previous experience, the main focus will be on Caribbean, Latin America and Africa, where they believe they will be able to access opportunities with low capex entry costs and potentially transformational upside.

6. Background to and strategic rationale for Admission and Cancellation

The Existing Ordinary Shares are currently listed on the Standard Segment of the Official List and admitted to trading on the Main Market.

The Board has undertaken a review to determine the most appropriate trading platform for the Ordinary Shares for the benefit of Shareholders. The Board has carefully considered the proposed Admission to AIM and the simultaneous cancellation from the Standard Segment of the Official List and of trading on the Main Market. The Board believes it is in the best interests of the Company and its Shareholders as a whole for the following reasons:

- the Directors believe AIM is a market appropriate for a company of the Group's size and nature, and it is a market which will help attract new investors, providing a platform to promote the Group and trading in its Ordinary Shares;
- the Directors believe AIM may offer greater flexibility with regard to future corporate transactions and may enable the Company to agree and execute certain potential transactions more cost effectively than a company on the Official List;
- shares in companies that are traded on AIM are deemed to be unlisted for the purposes of certain areas of UK taxation. Following Cancellation and Admission, individuals who hold Ordinary Shares

may, provided that the two-year holding period is satisfied, therefore be eligible for inheritance tax benefits. Shareholders and prospective investors should consult their own professional advisers on whether an investment in an AIM security is suitable for them and to what extent any potential UK inheritance tax benefit referred to above is available to them;

- shares traded on AIM can be held in ISAs (in the same way as shares traded on the Main Market);
- transactions in securities admitted to trading on AIM are exempt from stamp duty and stamp duty reserve tax, which may help increase liquidity in the trading of the Ordinary Shares on AIM; and
- the Directors believe that the Group should continue to appeal to institutional investors following Admission and, in light of the possible tax benefits mentioned above, the Directors believe that being admitted to AIM will make the Ordinary Shares more attractive to retail investors, thereby potentially increasing liquidity.

Accordingly, in accordance with the AIM Rules, application has been made for the Existing Ordinary Shares to be admitted to trading on AIM. It is expected that Admission will become effective and dealings in the Existing Ordinary Shares will commence on AIM at 8.00 a.m. on 1 March 2019.

7. Directors and Senior Management

Directors

Details of the Directors and their backgrounds are as follows:

Alan <u>Graham</u> Martin, *Non-Executive Chairman* (aged 64)

Mr Martin is an experienced senior natural resources executive and brings a wealth of international expertise. He is currently a Non-Executive Director at Kenmare Resources plc, one of the leading global producers of titanium minerals and zircon listed in London and Dublin. He has also previously served as an Executive Director, General Counsel and Company Secretary at Tullow Oil plc.

From 1997 until 2016, Mr Martin was centrally involved in the growth of Tullow Oil plc into a FTSE100 business, and in the company's transformative M&A programme. Prior to Tullow Oil plc, Mr Martin was a partner at the US energy law firm Vinson & Elkins LLP, having started his legal career in Scotland.

<u>Brian</u> Edward Andrew Larkin, *Chief Executive Officer* (aged 37)

Mr Larkin is a Qualified Accountant and has an MBA from Dublin City University. He has extensive oil and gas industry experience having worked for both Tullow Oil Plc and Providence Resources Plc. At Tullow Oil Plc, Mr Larkin held positions in both finance and commercial, and worked on a variety of production, development and exploration projects in South America and Asia and carried out numerous investment case recommendations.

At Providence Resources Plc, Mr Larkin worked in senior finance and commercial positions. During his time with Providence Resources Plc, Mr Larkin worked on a wide portfolio of assets in regions including the Gulf of Mexico, offshore Ireland, onshore United Kingdom, and offshore Nigeria.

<u>Jonathan</u> James Leather, *Chief Operating Officer* (aged 42)

Dr Leather has 18 years experience in the oil industry and holds a Geology degree from Oxford University, a PhD in Sedimentology from Trinity College, Dublin, and an MBA from Warwick University.

He worked for Tullow Oil Plc from 2007 to 2015, where he held a number of senior positions, including membership of the Global Exploration Leadership Team. He also managed Tullow Oil Plc's Subsurface Technology Group – a team he established and built up to provide specialist technical input across the company in both exploration and development. As part of this, Dr Leather worked on global assets and opportunities ranging from onshore producing fields to deepwater frontier exploration.

Prior to Tullow Oil Plc, Dr Leather worked for Shell U.K. Limited. During his time there he was involved in a number of exploration and development projects, and worked on North Sea, European, Middle Eastern and Malaysian assets.

Alberto Cattaruzza, *Non-Executive Director* (aged 81)

Mr Cattaruzza graduated as a Chemical Engineer from the University of Padua and, having worked in Germany for LURGI GmbH, he returned to Italy in 1966 and joined Chevron Oil Italiana s.p.a. In 1995, Mr Cattaruzza joined the Oilinvest Group, operating in Europe under the brand name Tamoil, as Managing Director of their German affiliate. He was later appointed Oilinvest Refining & Marketing Officer and a board member of several other group companies. In 2001, Mr Cattaruzza started an independent entity providing technical and business consultancy services in the oil sector and is co-founder of Il Delfino, a non-profit cultural association.

Senior Management

Rodney Mooney, *Finance Manager* (aged 39)

Mr Mooney joined the Company in October 2017. Prior to joining the Company, he worked for Tullow Oil Plc from 2007 until 2015 where he held a senior finance position within their Asia and South American business unit. He is a chartered accountant in Ireland with 12 years post qualification experience mostly within the upstream oil and gas industry but also has private company and charity sector experience. His main areas of expertise include management accounting and budgeting, group consolidation in IFRS, statutory reporting and mergers & acquisitions.

8. Corporate Governance

From Admission, the Company is required under the AIM Rules to comply with a recognised corporate governance code to be chosen by the Board. The Board recognises the importance of sound corporate governance and intends that the Company will comply with the provisions of the QCA Code. The Company shall disclose on its website how it complies with the QCA Code and, where it departs from the QCA Code, will explain the reasons for doing so.

The Board currently comprises 2 executive directors, Brian Larkin and Jonathan Leather, and 2 non-executive directors, Alberto Cattaruzza and Graham Martin, who are considered by the Board to be independent.

The Company has committed to (i) appoint another independent non-executive director with appropriate financial expertise within six months of the date of Admission and (ii) to appoint a Finance Director at the appropriate juncture (for example, if the Company undertakes a larger transaction or progresses to production).

The Board is responsible for formulating, reviewing and approving the Group's strategy, budgets and corporate actions.

The Board has established an audit committee, a remuneration committee and a conflicts committee with formally delegated duties and responsibilities.

Audit committee

The Audit Committee which comprises of Alberto Cattaruzza and Graham Martin, has the primary responsibility for monitoring the quality of internal control and ensuring that the financial performance of the Group is properly measured and reported on and for reviewing reports from the Company's auditors relating to the Group's accounting and internal controls. The committee is also responsible for making recommendations to the Board on the appointment of auditors and the audit fee and for ensuring that the financial performance of the Group is properly monitored and reported. The audit committee will meet not less than three times a year.

Remuneration committee

The remuneration committee which comprises Alberto Cattaruzza and Graham Martin, is responsible for the review and recommendation of the scale and structure of remuneration for senior management, including any bonus arrangements or the award of share options with due regard to the interests of the Shareholders and the performance of the Group.

Conflicts committee

The conflicts committee which comprises Alberto Cattaruzza and Graham Martin considers on behalf of the Board any actual or potential conflict of interest between any member of the Board and the Group. The conflicts committee shall meet at least twice a year and otherwise as required.

AIM Rules compliance committee

From Admission, the Company will have established an AIM Rules compliance committee which will comprise Graham Martin and Brian Larkin and which prime responsibility will be to ensure the Company has sufficient procedures in place to ensure ongoing compliance with the AIM Rules. The Company has adopted an AIM Rules compliance code to ensure that they have sufficient procedures for ensuring compliance with the AIM Rules.

The Company does not have a nomination committee as the Board does not consider it appropriate to establish such a committee at this stage of the Company's development. Decisions which would usually be taken by the nomination committee will be taken by the Board as a whole.

9. Share dealing code

The Board has adopted a share dealing code for PDMRs and their Closely Associated Persons, which complies with Rule 21 of the AIM Rules and also with the requirements of MAR. The share dealing code provides that there are certain periods during which dealings in the Company's Ordinary Shares cannot be made. Such periods include the periods leading up to the publication of the Company's financial results, including interim results, and any periods in which the Directors and other relevant employees and key personnel may be in possession of unpublished price sensitive information.

The Company will take all reasonable steps to ensure compliance by PDMRs and their Closely Associated Persons with the share dealing code.

10. Anti-Bribery and Corruption Policy

The Bribery Act 2010 which came into force in the UK on 1 July 2011 prescribes criminal offences for individuals and businesses relating to the payment of bribes and, in certain cases, a failure to prevent the payment of bribes. The Company has therefore established procedures and adopted an anti-bribery and corruption policy designed to ensure that no member of the Group engages in conduct for which a prosecution under the Bribery Act may result.

11. Social Media Policy

The Company has adopted and implemented a Social Media Policy which details the manner in which all employees, officers, consultants, contractors and other personnel interact with social media in relation to the Company. This policy deals with the use of all forms of social media including Facebook, Linkedin, Twitter, Instagram, ADVFN bulletin board, iii bulletin board and all other social networking sites, internet postings, bulletin boards and blogs. It applies to use of social media for business purposes as well as personal use that may affect the business in any way. It is designed to ensure that there is no unauthorized release of potentially price sensitive information regarding the Company so that all such information is released in the first instance through the correct authorized regulatory news services and that no misleading information is contained in unauthorized media channels. The policy is also designed to mitigate the risk of use of terminology in the media being inconsistent with the Company's authorized regulatory announcements.

12. Admission

Application has been made to the London Stock Exchange for the entire Existing Share Capital to be admitted to trading on AIM. It is expected that Admission will become effective and dealings in the Ordinary Shares on AIM will commence at 8.00 am on 1 March 2019. Percentage of Ordinary Shares not in public hands at Admission is 4.64 per cent.

13. Interests in Ordinary Shares and Lock-In Arrangements

At Admission, the Directors and the Finance Manager will in aggregate be interested in, directly and indirectly, 16,045,265 Ordinary Shares representing approximately 4.64 per cent. of the Company's Existing Share Capital. Interests in a further 14,633,500 Ordinary Shares are in the form of Warrants (over unissued Ordinary Shares granted on 25 July 2017, further details of which are set out at paragraph 11.17 of Part VII of this Document) and 11,117,648 Options (further details of which are set out in paragraph 6.1 of Part VII of this Document). On the assumption that all Warrants and Options are exercised on Admission, the Directors and the Finance Manager would in aggregate be interested in, directly and indirectly 41,796,413 Ordinary Shares representing approximately 9.52 per cent. of the fully diluted ordinary share capital of the Company.

Each of the Directors and the Finance Manager have entered into irrevocable undertakings with the Company, Beaumont Cornish and Optiva Securities that they, conditionally upon Admission, will not (and will procure, insofar as they are able, that their associates will not) dispose of any interest in Ordinary Shares held by them or their associates for a period of one year from Admission, save in certain circumstances. In addition, they have agreed for a further period of 6 months after expiry of the lock in period that, subject to certain exceptions, they will only sell interests in Ordinary Shares held by them through the Company's broker from time to time and on an orderly market basis.

14. Financial Reporting

The Company operates a December year end. It is anticipated that the preliminary statement of results for each year will be announced by the end of June and that an interim statement of the results will be announced by the end of September each year.

Part IV of this Document contains:

- the audited financial information relating to the Group for the period of nine months ended 31 December 2015, the year ended 31 December 2016 and the year ended 31 December 2017; and
- the unaudited consolidated financial information relating to the Group for the six month period ended 30 June 2018.

Part V of this Document contains the unaudited pro forma statements of net assets as at 30 June 2018 of the Company.

15. Dividend Policy

The Directors do not intend to declare a dividend at the current time and it intends to retain all of its future earnings, if any, to finance the growth and development of the Company's and the Group's business. Under English law, a company can only pay cash dividends to the extent that it has distributable reserves and cash available for this purpose. The Company may not pay dividends if the Directors believe this would cause the Company to be inadequately capitalized or if, for any other reason, the Directors conclude it would not be in the best interests of the Company and the Group. Any of the foregoing could limit the payment of dividends to Shareholders or, if the Company does pay dividends, the amount of such dividends. Any return to Shareholders will, for the foreseeable future, therefore be limited to appreciation of their investment.

16. Takeover Code

The Company is subject to the UK City Code on Takeovers and Mergers published by the Panel on Takeovers and Mergers. Further information regarding the Takeover Code is set out in paragraph 14 of Part VII of this Document.

17. Share Options

The Directors believe that the Company's success is highly dependent on the quality and loyalty of the current and future directors, employees and consultants to the Group. To assist in the recruitment, retention and motivation of high quality personnel, the Board believes the Company must have an effective remuneration strategy. The Directors consider that an important part of this remuneration strategy is the ability to award equity incentives and, in particular, share options.

The Board has not adopted a formal share option scheme in order to award Options to directors, employees and consultants at present. However, it will take into consideration the recommendations of the Remuneration Committee in determining the appropriate terms in relation to the award of future Options. To date, the Company has only awarded 11,117,648 Options, further details of which are set out in paragraph 4.11 of Part VII of this Document.

18. Risk Factors

The Company's business is dependent on many factors and prospective investors should read the whole of this Document. In particular, your attention is drawn to the "Risk factors" set out in Part III of this Document.

19. Taxation

The Company is registered in the UK. Information regarding taxation is set out in Part VI of this Document. These details are intended only as a general guide to the current tax position in the UK. If an investor is in any doubt as to his or her tax position or is subject to tax in a jurisdiction other than the UK, he or she should consult his or her own independent financial adviser immediately.

20. Additional Information

Potential investors should read the whole of this Document and not just rely on the information contained in this Part I. Your attention is drawn to the information set out in Parts II to IX of this Document, which contain further information on the Group and projects.

Copies of this Document will be available to the public, free of charge, from the Company's registered office until the expiry of one month from the date of publication of this Document.

PART II

MARKET OVERVIEW

The United Kingdom

The UK is the second largest producer of oil in Europe, after Norway, and the third largest producer of gas, after Norway and the Netherlands.

The UK oil and gas industry in 2017 supported some 300,000 jobs directly and indirectly down from 450,000 at the start of 2014.

The decline in drilling activity over the last decade, particularly exploration and appraisal, has been exacerbated by the downturn. Exploration activity has declined by one third in just three years from 2013 to 2016. In 2016, £8.3 billion of capital expenditure was invested in the UK Continental Shelf, down from £11.7 billion in 2015. Less than £7 billion of capital expenditure was expected in 2017.

The UK Government's Office for Budgetary Responsibility's ("OBR's") Fiscal Sustainability Review in June 2015 provided estimates of long term reserves of oil and gas and production. The OBR said: "Our central long-term assumption is that production falls by 5 per cent. a year from 2020 onwards. For our low production scenario we assume a 7.8 per cent. a year fall. Our high production scenario sees production remaining as we expect in 2019 for a further 5 years, with a fall of 5 per cent. a year thereafter." For oil and gas reserves, the OBR said: "Over the long term, recoverable reserves are clearly on a declining path as the basin matures and resources are exhausted or become increasingly difficult or uneconomic to extract."

Onshore Oil and Gas

The onshore oil and gas industry in the UK has been in existence for over 150 years. Before the First World War, the UK obtained almost all of its oil and gas from outside the country. Oil was discovered in Scotland in 1851 followed by gas in England in 1896.

During both world wars the need for Britain to produce its own oil to help the war effort rather than rely on imports became of real importance to the UK Government and legislation was introduced to enable companies to explore for hydrocarbons more readily.

In 1973, the Wytch Farm oilfield in Eastern Dorset was opened and today it is the largest onshore oilfield discovery in the UK.

Following significant offshore North Sea oil and gas discoveries in the 1960s and the rapid growth in offshore production, onshore oil and gas activity also started to accelerate again after the 1979 oil crisis. As prices rose, domestic production in both the onshore and offshore became increasingly important.

Onshore UK today, there are 120 sites with 250 operating wells producing in total between 20,000 and 25,000 boepd and around 2,000 wells have now been drilled. Approximately 250,000 barrels per day of produced water is disposed of under permits from the relevant authorities.

The onshore oil and gas industry is regulated by a number of statutory bodies including the Environment Agency in England, Scottish Environment Protection Agency in Scotland and Natural Resources Wales in Wales, the Health and Safety Executive, the Department for Business, Energy and Industrial Strategy and the Oil and Gas Authority. The OGA operates as a government company whose role is to regulate, influence and promote the UK oil and gas industry in order to maximise the economic recovery of the UK's oil and gas resources. Since its establishment on 1 April 2015, the OGA has been responsible for regulating both onshore and offshore oil and gas operations in the UK. This includes: licensing, exploration and production, the oil and gas fields and wells and the oil and gas infrastructure.

A UK Petroleum Exploration and Development Licence ("PEDL") allows a company to pursue a range of oil and gas exploration, development and production activities, subject to conditions placed upon them (if any), necessary drilling/development consents and planning permission. The PEDL is the current form of UK onshore oil and gas licence; older licences have the PL prefix.

The 14th Landward Licensing Round was launched on 28 July 2014 and closed on 28 October 2014. A total of 95 applications were received from 47 companies covering 295 ordnance survey blocks. On 17 December 2015 it was announced that licences for a total of 159 blocks were formally offered to successful applicants.

Similar to the North Sea offshore oil and gas exploration and production sector, there are a number of private and unquoted companies active in the UK onshore sector:

- companies listed on AIM;
- a number of private groups; and
- a number of larger London listed exploration and production companies, international oil companies and UK and international energy utilities.

Offshore Oil & Gas

The offshore oil and gas revolution in the UK began in the late 1960's with the landing of first gas from the West Sole Field in the North Sea.

With the Organization of the Petroleum Exporting Countries Oil Crisis of the early 1970s, oil prices quadrupled and the search for oil in non-traditional oil producing countries became more attractive. New fields were discovered and the Forties, Brent and Piper, became key suppliers to the UK's energy mix. Oil production would peak in the late 1990s.

Exploration in the North Sea continued and while success was more limited, the discovery of Buzzard in 2001, indicated that there was still considerable opportunity in the North Sea.

The continuing success of operations in UK offshore market, is in part dependent on a favourable taxation regime. The 2011 tax rise by the Government demonstrated that the industry remains sensitive to price shocks. A 12 per cent. levy significantly reduced exploration activity. The tax changes were relatively short lived and the industry rebounded on the back of a more favourable regime that persists to this day.

While the North Sea has declined in terms of importance, it remains a key producer. The profile of owner has changed markedly, with asset sales seeing majors moving on, to be replaced by a new, aggressive, independent sector. This has led to significant investment in the North Sea in recent years, with many new entrants.

The investments being made are a strong vote of confidence of the remaining resource in UK waters. There continues to be a significant resource in place. There is an existing skill set to develop and exploit this resource. There is a favourable regime and broadly stable political and planning framework. There is strong existing demand in the UK for oil and gas – Oil and gas provides approximately 70 per cent. of UK primary energy.

The Italian Gas Industry

The gas industry in Italy developed after World War Two around the Italian oil and gas multinational, ENI. While searching for oil during World War Two, the state company Agip (Azienda Generale Italiana Petroli) found large quantities of gas in the Po Valley region. A pipeline network was created to reach the large factories in the northern part of the country and this facilitated the expansion of local manufacturing industry in the 1950's and 1960's. The profits from natural gas sales were reinvested into exploration and production activities and in the expansion of the pipeline infrastructure. By 1960, Italy was the largest gas producer and consumer in Europe and the gas network continued to expand to other parts of the country. With a rapid increase in gas consumption in the industrial, residential and commercial sectors, this growing demand began to outstrip domestic supply.

The first imports into Italy started in 1971 when the liquefied natural gas import terminal at Pannigaglia began operations. Since the early 1990's, the length of the Italian pipeline network has tripled.

The liberalization process started in 1998 with the EU gas directives, designed to create an internal market for gas. Vertically integrated national companies were broken up, allowing competitors to enter on the supply side and customer switching on the demand side.

More than ten years later, the gas industry had been fully liberalized; the Directors believe that competition has yet to reach its full potential with a few players still dominating the upstream and wholesale sectors. Nevertheless, as with the rest of Europe, Italian gas deliveries to power generation are continuing to develop. The Punto di Scambio Virtuale, ("PSV"), the virtual hub, was created in 2003 and a gas exchange with spot gas (day ahead, intraday) and balancing gas platforms was launched in 2010 and 2011. Traded volumes are fast increasing and the PSV day-ahead process has started to track spot prices of North West European hubs since the end of 2012 thanks to governmental measures to improve liquidity and access to the market to new entrants.

According to the Snam Rete Gas ten-year network development plan 2015-2025 Italy consumed 2.38 tcf in gas in 2015, and this expected to grow at 1.9 per cent. per annum to 2025. Of this only 227 bcf (0.23 tcf), or 11 per cent., was produced domestically, with the remaining 2.15 tcf imported from several countries, notably from Russia and from countries in the Mediterranean area.

On 13 February 2019, the law No. 12 of February 11, 2019 on "*Conversion into law, with amendments, of the law decree December 14, 2018, No. 135, containing urgent provisions on matters of support and simplification for enterprises and for the public administration*" ("Law 12/2019") came into force in Italy.

Paragraph 4 of Article 11-*ter* on "Sustainable energy transition plan of the appropriate areas" ("Plan") of the Law 12/2019 provides for the suspension of all administrative procedures related to the granting of liquid and gaseous hydrocarbons exploration licenses. The suspension is provided for a period up to 24 months while the Italian Ministry of Economic Development and the Italian Ministry of Environment and Protection of the Land and Sea approve the adoption of the Plan which will identify the defined framework for the areas where liquid and gaseous hydrocarbons' prospection, exploration and production activities can be performed on the national territory.

Paragraph 5 of Article 11-*ter* of the Law 12/2019 provides that there is no suspension for the award procedures related to the granting of liquid and gaseous hydrocarbons production licences filed prior to the date that Law 12/2019 came into force on 13 February 2019. However, if the Plan is adopted and the area where the application for production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the Italian Ministry of Economic Development will reject the application for the production licence if it has not awarded before the Plan becomes effective; and (b) if the Plan is adopted and the production licence is awarded before the Plan becomes effective but the production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the production licence will be effective until the expiry date but no new applications for the extension will be allowed.

Jamaican Oil and Gas

Exploration activities in Jamaica have occurred in two phases. The earlier phase spanned 1955 – 1973, done by private companies, and more recently 1978 – 1982 by the PCJ.

Between 1955 and 1973, seven (7) exploratory wells were drilled, one (1) offshore and six (6) onshore. Immediately following on the establishment of the state-owned Petroleum Corporation in 1979, the momentum of activity increased with the drilling of an additional three (3) wells onshore and one (1) offshore during the period 1980-1981.

There have been oil or gas shows in 10 of the 11 onshore and offshore wells drilled in Jamaica to date. The offshore area to the South of the island has been identified as having good frontier exploration potential encompassing three geological provinces, the Pedro Bank carbonate platform and the Walton and "Southern" sub basins. Multiple leads have been identified on existing seismic data which lie in 25m to 2,000m water depths.

With advancements in the geological and geophysical sciences over the past two decades, Jamaica is being viewed through "new" exploration lenses and is likely to benefit from this reawakening of interest in frontier provinces inside the Caribbean.

PCJ was formed in June 1977, and is empowered by the Petroleum Act of 1979, to pursue the development of Jamaica's energy resources with exclusive rights to explore for oil and develop Jamaica's petroleum resources. The entity initially was mandated to explore for oil and gas along with the procurement of refining, retailing and distribution of petroleum products.

A geological study recently conducted by the PCJ and integrated geoscience company, CGG Robertson (UK) Ltd has revealed further encouraging signs for possible petroleum potential on and off-shore Jamaica.

The investigations, which were carried out over an 18 month period discovered two independent live oil seeps in different sections of Jamaica's oil blocks. Detailed analysis confirmed active working petroleum systems that are generating and expelling liquid hydrocarbons to the surface.

Trends

The Directors believe that increasing global industrialisation and urbanisation, particularly in emerging African and Latin American markets, plus increased concern about security of energy supply in some developed economies is likely to lead to increased local demand for energy production in the medium to long term. Over the same period, the Directors believe that the supply of oil and gas in these markets will be constrained by insufficient investment to keep pace with increased demand and by exploration and development challenges, which are likely in each case to generate sustained inflation in commodity pricing. Indeed, the oversupply of oil and gas that has been experienced for much of the last 3 years now appears to be balancing, and commodity prices have remained at a reasonably stable level for the last 6 months.

PART III

RISK FACTORS

An investment in the Ordinary Shares involves a high degree of risk, including risks in relation to the Group's business and strategy, the oil and gas sector, potential conflicts of interest and risks relating to taxation.

Prospective investors should carefully consider all of the information in this Document, including the following risk factors, before investing in the Ordinary Shares. Additional risks and uncertainties not presently known to the Company and the Directors or that the Company and the Directors currently consider to be immaterial may also adversely affect the Group's business, operations and financial condition. If any events or circumstances giving rise to any of the following risks, together with possible additional risks and uncertainties of which the Group and the Directors consider not to be material in relation the Group's business actually occur, the Group's business, financial condition and results of future operations could be materially and adversely affected. In such circumstances, the value of the Ordinary Shares could decline due to any of these risks occurring and investors could lose part or all of their investment.

Prospective investors should pay particular attention to the fact that some of the Group's assets are located overseas, in countries which have legal regulatory regimes that differ materially from the legal and regulatory regimes of the United Kingdom.

There can be no certainty that the Company will be able to successfully implement the strategy as set out in this Document. No representation is or can be made as to the future performance of the Company and there can be assurance that the Company will achieve its objectives.

RISKS RELATING TO THE COMPANY'S BUSINESS AND STRATEGY

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any existing properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation on economically favourable terms or at all. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net reserves to return a profit after drilling, operating and other costs and taxes, royalties or their equivalents. Completion of a well does not assure a profit on investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

While diligent well supervision and effective maintenance operations can contribute to maximising productions rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering sour gas releases and spills, any of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the operators of the Company concessions are required to maintain liability insurance in an amount that they consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all of the risks typically associated with such operations, including encountering unexpected formalities or pressures, premature decline of reservoirs and the invasion of water into producing formations, with losses resulting from the occurrence of any of these risks.

Reliance on Partners

The Company's exploration, development and productions assets currently comprises: (i) a 26.25 per cent. interest in Waddock Cross PL090 Licence; (ii) an 18.85 per cent. interest in the Exploration PL090 Licence; (iii) a 20 per cent. interest in the Podere Gallina Licence; (iv) a 20 per cent. interest in the Walton-Morant Licence; (iv) a 10 percent. interest in the P1918 Licence; and a 95 per cent. interest in the P2366 Licence. Furthermore, the Company has the option to farm-in to the P2264 Licence, which would provide the Company, assuming (i) the option is exercised, with a 24 per cent. interest therein, such licence including the Acle prospect and (ii) that titleholder is not forced to relinquish the block for failing to meet the conditions set by the OGA. The OGA has given the titleholder until 28th February 2019 to show a firm commitment in the form of an executed farm in agreement that will result in the drilling of an exploration well. If this condition is not achieved and without a further extension by the OGA, it is likely that Swift will be forced to relinquish the block. Accordingly, UOG's option to farm in with lapse at the same time. There is currently no certainty that a farm in agreement will be executed by the deadline set by the OGA. Accordingly, the Company is reliant on its partners, and notwithstanding that the Company performs due diligence on its partners' and potential partners' finances before entering into any such acquisition or farm-in, and fully expects current or future field partners to meet their obligations, any failure or delay in their doing so could have a material effect on the Company's ability to implement its stated strategy and consequently on its financial position and performance.

Title Matters

The Company would obtain the right to explore its assets and, to the best of its knowledge, would determine that those rights are in good standing; however, this right would be dependent on both the Company meetings its obligations under its contracts in relation to assets and meeting its obligations under their licences and/or contracts with applicable governments or governmental authorities in relation to the projects. The failure of the Company to perform its obligations could result in the applicable exploration and development licenses and/or agreements being revoked or suspended. Furthermore, in any event, no assurance can be given that applicable governments will not revoke or significantly alter the conditions of the applicable exploration and development authorisations, and that such exploration and development authorisations will not be challenged or impugned by third parties. There is no certainty that such rights or additional rights applied or re-applied for will be granted or renewed on terms satisfactory to the Company. There can be no assurances that claims by third parties against the Company's assets or other rights will not be asserted at a future date.

As at the date of this Document, the term of the exploration licence in Italy conventionally known as the Podere Gallina (the "Italian Exploration Licence") in which UOG has a 20 per cent. interest expired on 3 February 2018. The Italian branch of PVO applied in July 2016 to the Ministry of Economic Development, General Directorate for Energy and Natural Resources – the National Mining Office for Hydrocarbons and Geothermal Energy (the "Ministry") for the first 3-year extension of the exploration period. UOG originally expected the licence extension to be awarded in the second quarter of 2018, with such extension having retrospective effect from 3 February 2018. However, as at the date of this Document, the extension has not been granted yet to the titleholder and there can no assurances or guarantees as to when such extension will be granted. Accordingly, the titleholder can finish the works that have been authorized by the Ministry but any further work not approved before 2 February 2018 can only be undertaken after an authorisation by the Ministry and an extension of the Italian Exploration Licence.

On 13 February 2019, the law No. 12 of February 11, 2019 on "*Conversion into law, with amendments, of the law decree December 14, 2018, No. 135, containing urgent provisions on matters of support and simplification for enterprises and for the public administration*" ("Law 12/2019") came into force in Italy.

Paragraph 4 of Article 11-*ter* on "Sustainable energy transition plan of the appropriate areas" ("Plan") of the Law 12/2019 provides for the suspension of all administrative procedures related to the granting of liquid and gaseous hydrocarbons exploration licenses. Therefore, the procedure relating to the extension of the Italian Exploration Licence has been suspended. The suspension is provided for a period up to 24 months while the Italian Ministry of Economic Development and the Italian Ministry of Environment and Protection of the Land and Sea approve the adoption of the Plan which will identify the defined framework for the areas where liquid and gaseous hydrocarbons' prospection, exploration and production activities can be performed on the national territory.

If the Plan is not adopted within the period of 24 months of the date that the Law 12/2019 came into force, then the administrative procedure related to the extension of the Italian Exploration Licence can resume. However, if the Plan is adopted and the area where the Italian Exploration Licence is located is defined by the Plan as not compatible for the liquid and gaseous hydrocarbons' prospection, exploration and production activities, the application for extension will be rejected by the Italian Ministry of Economic Development pursuant to the new law.

Even if the administrative procedure related to the extension of the Italian Exploration Licence resumes, there are no guarantees or assurances that the extension will be granted. Furthermore, the Italian Exploration Licence will expire if an extension is not granted. If such expiry did occur, the Group would potentially have to expend additional resources, in conjunction with PVO or otherwise, to consider its options as to whether to pursue this interest and/or explore alternative asset opportunities.

Although PVO filed an application in May 2018 for a production licence to develop the Selva Gas Field in Italy and a positive response was issued by the competent ministry in the Italian Government, there are no certainty, assurances or guarantees that PVO will be successful with its application and be awarded the production licence at the end of the award process. The next step of the award process is to carry out an environment assessment and a positive result is required to proceed to the next stage of the award process. If a positive environment assessment is not obtained, the application will not proceed. Even if a positive environment assessment is achieved, a resolution by the local government of the region Emilia Romagna will need to be passed. Furthermore, whilst the application by PVO for the production licence and the related award procedure are not suspended by the Law 12/2019, the application is affected by the Law 12/2019 as follows: (a) if the Plan is adopted and the area where the application for production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the Italian Ministry of Economic Development will reject the application for the production licence if it has not awarded before the Plan becomes effective; and (b) if the Plan is adopted and the production licence is awarded before the Plan becomes effective but the production licence is located in territory defined by the Plan as not compatible for liquid and gaseous hydrocarbons' prospection, exploration and production activities, the production licence will be effective until the expiry date but no new applications for the extension will be allowed.

The above outline of the effects of the Law 12/2019 is for guidance only as at the date of this Document. There may be further changes and/or interpretation as the full impact is assessed by the Company and interested parties.

Licence Risks

Despite successful acquisitions of interests in new licences, there is no assurance that any subsequent work carried out under any of these licences will be successful or that it will be effective in increasing the value of any of these assets.

No assurance can be given that the Company will be able to carry out the work required under each of the licences it has an interest in to effectively realise increased value. In addition, even if the Company completes a licence acquisition, general economic and market conditions or other factors outside the Company's control could make its strategies difficult or impossible to implement. Any failure to implement its programme on a licence successfully and/or failure of the programme to deliver the anticipated benefits could have a material adverse effect on the Company's results of operations and financial condition.

The Company's current exploration and development objectives are dependent upon the grant, renewal or continuance in force of appropriate surface and/or sub-surface use contracts, license, permits, regulatory approvals and consents which may be valid only for a defined time period, ma be subject to limitations and may provide for withdrawal in certain circumstances. There can be no assurance that such surface and/or sub-surface use contracts, licences, permits, regulatory approvals and consents would be granted, renewed or continue in force or, if so, on what terms.

Withdrawal of licences, termination of surface and/or sub-surface use contracts or failure to secure requisite licences or the cession thereof of surface and/or sub-surface use contracts in respect of any of the Company's operations may have a material adverse impact on the Company's business, operating results and financial condition.

Estimate Risks

The oil and gas contingent and prospective resources data and the production profiles and development plans for the Company's assets, detailed in this Document, are only estimates. There are uncertainties inherent in estimating oil and gas resources and reserves for any oil and gas asset. These uncertainties are generally greater for areas where there has been limited historic hydrocarbon exploration. In addition, the contingent and prospective resource estimates contained in this Document are derived from the interpretation of seismic and other geoscientific data and, where appropriate, drilling results. Such interpretation and estimates of the amounts of oil and gas resources are subjective and the results of drilling, testing and production subsequent to the date of any particular estimate may result in substantial revisions to the original interpretation and estimates.

Internal Systems and Controls

The Company faces risks frequently encountered by developing companies such as under-capitalisation, cash shortages and limited resources. In particular, its future growth and prospects will depend on its ability to manage growth and to continue to maintain, expand and improve operational, financial and management information systems on a timely basis, whilst at the same time maintaining effective cost controls. Any damage to, failure of or inability to maintain, expand and upgrade effective operational, financial and management information systems and internal controls in line with the Company's growth could have a material adverse effect on its business, financial condition and results of operations.

Retention of Key Business Relationships

The Company relies significantly on strategic relationships with other entities, on good relationships with regulatory and governmental departments and upon third parties to provide essential contracting services. There can be no assurance that its existing relationships will continue to be maintained or that new ones will be successfully formed and the Company could be adversely affected by the changes to such relationships or difficulties in forming new ones. Any circumstances which causes the early termination or non-reward of one or more of these key business alliances or contracts or the failure to successfully form new ones, could adversely impact the Company, its business, operating results and prospects.

Attraction and Retention of Key Employees

The Company's success depends on its current and future executive management team. If any key person was to resign, there would be a risk that no suitable replacement with the requisite skills, contacts and industry experience would be found to replace such person. The senior executive personnel have equity interests in the Company. Notwithstanding this, if key personnel were to leave the Company, it could have a material adverse effect on the Company's business, financial condition and operating results.

Operating History

The Company, through the establishment of UOG Ireland, has operated since April 2015. There can be no assurance that losses will not occur in the short term or that the Company will be profitable in the future. Success will depend on the outcome of exploration and development programmes, and the Directors' ability to take advantage of further opportunities which may arise.

Although the Company will seek to evaluate the risks inherent in a particular target licence or farm-in opportunity, it cannot offer any reassurance that it will make a commercially viable discovery or an accurate assessment of all the significant risks. Furthermore, no assurance can be given that an investment in the

Shares will provide investors with more upside than a direct investment, if such opportunity were available, in a target licence or farm-in opportunity.

Political Conditions

Although political conditions in Europe are generally stable, changes may occur in its political, fiscal and legal systems, which might adversely affect the ownership or operation of the Company's interests including, *inter alia*, changes in exchange rates, exchange control regulations, expropriation of oil and gas rights, changes in government and in legislative, fiscal and regulatory regimes. The Company's strategy has been formulated in the light of the current regulatory environment and likely future changes.

Although the Directors believe that the Company's activities will be carried out in accordance with all applicable rules and regulations, no assurance can be given that new rules, laws and regulations will not be enacted or that existing or future rules and regulations will not be applied in a manner which could serve to limit or curtail exploration production or development of the Company's business or have an otherwise negative impact on its activities. Amendments to existing rules, laws and regulations governing the Company's operations and activities or increases in or more stringent enforcement, implementation thereof, could have a material adverse impact on the Company's business, results of operations and financial condition and its industry in general in terms of additional compliance costs.

"Brexit" and the EU/Eurozone

The decision by the United Kingdom to exit from the European Union could have an impact on the Company's business, financial condition and results of operations. There still remains significant uncertainties in relation to the terms and time frame within which such an exit (due by law to take place on Friday, 29 March 2019) would be effected, and there are significant uncertainties as to what the impact will be on the fiscal, monetary and regulatory landscape in the UK, including *inter alia*, the UK's tax system, the conduct of cross-border business and export and import tariffs. There is also uncertainty in relation to how, when and to what extent these developments will impact on the economy in the United Kingdom and the future growth of its various industries, including the oil and gas sector, and on levels of investor activity and confidence, on market performance and on exchange rates. However, it should be reported that whilst the Bank of England has recently cut its growth target for the United Kingdom it is still forecasting positive growth. Equally, there are widely reported concerns about the future economic conditions of the EU and the Eurozone, with both Germany and Italy recently reported to have entered "recession" and the possible effects across the Eurozone from an Italian "debt pile" of 2.3 trillion euros representing 130 per cent. of GDP. Although it is not possible to predict the effects of possible economic and political uncertainty in either the United Kingdom or the European Union, any of these risks, taken singularly or in the aggregate, could have a material adverse impact on the Company's business, financial condition and results of operations.

Insurance Risk

The Company insures its operations in accordance with industry practice and plans to insure the risks it considers appropriate for its needs and circumstances. No assurance can be given that the Company will be able to obtain insurance coverage at reasonable rates or at all, or that any coverage it obtains will be adequate and available to cover any claims arising. The Company may become subject to liability for pollution or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. In the event that insurance coverage is not available or the Company's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, the Company's business and operations, financial results or financial position may be disrupted and adversely affected.

Currency Risk

The Company may make investments in currencies other than Sterling. Accordingly, the value of such investments may be adversely affected by changes in currency exchange rates notwithstanding the performance of the investments themselves, which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Company.

Fluctuations of Revenues and Operating Results

Future revenues, expenses and operating results of the Company could vary significantly from period to period as a result of a variety of factors, some of which are outside its control. These factors include general economic conditions, adverse movements in interest rates, conditions specific to the oil and gas services market, seasonal trends in revenues, capital expenditure and other costs. In response to a changing competitive environment, the Company may elect from time to time to make certain pricing, service or marketing decisions or investments that could have a material adverse effect on its revenues, results of operations and financial conditions and prospects.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time could be reduced or suspended entirely.

The market value of the Ordinary Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditure or property acquisitions using funds from operations.

To the extent that external sources of capital, including the issuance of additional Ordinary Shares, become limited or unavailable, the ability of the Company to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired.

Conflicts of Interest

The Company expects that any decision made by the Board will be made in accordance with their duty to act honestly and in good faith with a view to the best interests of the Company and exercise the care, diligence and skill which a reasonably prudent person would exercise in comparable circumstances, but there can be no assurance in this regard. In addition, each of the Directors is required to declare any matter in which they are interested as required by the Articles and the Act.

Legal Systems

The legal systems in jurisdictions in which the Company might operate in the future may be different to the legal systems in more established economies, such as the UK, which could result in risks such as (i) effective legal redress in the Courts of such jurisdictions being more difficult to obtain, whether in respect of a breach of law or in an ownership dispute; (ii) a higher degree of discretion on the part of Governmental authorities who may be susceptible to corruption; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, order and resolutions; or (v) relative inexperience of the judiciary and Courts in such matters.

In certain jurisdictions the commitment of local business people, Government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to the Company's licences and agreements. There can be no assurance that joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the actions of Government authorities or otherwise and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Given that the Jamaican legal system is based on the English common law system, the Directors are confident that the Company, whilst subject to a legal systems different to that in the UK insofar as it relates to the Walton-Morant Licence, is exposed to minimal risks insofar as such risks comprise issues the same or similar to those detailed in (i) through (v) above. Furthermore, the final court of appeal in Jamaica is The Judicial Committee of the Privy Council, which is based in London.

The Company has to date primarily focused on assets based in the UK and Europe, however the Directors will consider assets in other countries and regions on an opportunistic basis, and therefore may be subject to risks particular to less stable jurisdictions which could negatively impact its operations.

Litigation Risks

Whilst the Company currently has no outstanding litigation or disputes, there can be no guarantee that the current or future actions of the Company will not result in litigation since there have been a number of cases where the rights and privileges of natural resource companies have been the subject of litigation. The petroleum industry, as with all industries, may be subject to legal claims, both with and without merit, from time to time. The Directors cannot prejudice that such litigation may be brought against the Company, or any other company within the Group, in the future. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty of the litigation process, there can be no assurance that the resolution of any particular legal proceedings will not have a material adverse effect on the Company's financial position, results or operations. The Company's business may be materially adversely affected if it and/or its employees or agents are found not to have met the appropriate standard of care or not exercise their discretion or authority in a prudent or appropriate manner in accordance with accepted standards.

Environmental Risks and Hazards

All phases of the Company's operations are subject to environmental regulation in the various jurisdictions in which it operates. Environmental legislation is evolving in a manner that will require stricter standards and enforcement, increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their officers, directors and employees. There is no assurance that existing or future responsibility environmental regulation will not materially adversely affect the Company's business, financial condition and results of operations. Environmental hazards may exist on the properties on which the Company holds interests that are unknown to the Company at present and that have been caused by previous or existing owners or operators of the properties.

Governmental approvals and permits are currently, and may in the future be, required in connection with the Company's operations. To the extent such approvals are required and not obtained, the Company may be curtailed or prohibited from proceeding with planned exploration or development of mineral properties.

Failure to comply with applicable laws, regulations and permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment, or remedial actions. Parties engaged in mining operations, including the Company, may be required to compensate those suffering loss or damage by reason of the mining activities and may have civil or criminal fines or penalties imposed for violations of applicable laws or regulations.

Amendments to current laws, regulations and permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions. Parties engaged in mining operations, including the Company, may be required to compensate those suffering loss or damage by reason of the mining activities and may have civil or criminal fines or penalties imposed for violations of applicable laws or regulations.

Amendments to current laws, regulations and permits governing operations and activities of mining companies, or more stringent implementations thereof, could have a material adverse impact on the Company and cause increase in exploration expenses, capital expenditures or production costs, reduction in levels of production at producing properties, or abandonment or delays in development of new mining properties.

Competition

The oil and gas industry is very competitive and some of the Company's competitors have access to greater financial and technical resources which may give them a competitive advantage. As a result, the Company may not be able to compete effectively with competitors or gain access to future growth opportunities.

Risks Relating to Taxation

There can be certainty that the current taxation regime in the UK or overseas jurisdictions within which the Company currently operates or may operate in the future will remain in force or that the current levels of corporation taxation will remain unchanged. There can be no assurance that there will be no amendment to the existing taxation laws applicable to the Company, which may have a material adverse effect on the Company's financial position.

Any change in the Company's tax status or in taxation legislation in the UK could affect the Company's ability to provide returns to Shareholders. Statements in this Document concerning the taxation of investors in Shares are based on current law and practice, which is subject to change. The taxation of an investment in the Company depends on the individual circumstances of investors.

The nature and amount of tax which members of the Company expect to pay and the reliefs expected to be available to any member of the Company are each dependent upon several assumptions, any one of which may change and which would, if so changed, affect the nature and amount of tax payable and reliefs available. In particular, the nature and amount of tax payable is dependent on the availability of relief under tax treaties and is subject to changes to the tax laws or practice in any of the jurisdictions affecting the Company. Any limitation in the availability of relief under these treaties, any change in the terms of any such treaty or any changes in tax law, interpretation or practice could increase the amount of tax payable by the Company.

The Company's effective tax rate could be adversely affected by changes in the mix of earnings and losses in countries with differing statutory tax rates, certain non-deductible expenses arising from stock option compensation, the valuation of deferred tax assets and liabilities and changes in international tax laws and accounting principles. Increase in the Company's effective tax rate could materially affect the Company's net financial results.

In addition, the Company is subject to income tax audits by many tax jurisdictions. Although the Directors believe that the Company's income tax liabilities are reasonably estimated and accounted for in accordance with applicable laws and principles, an adverse resolution of one or more uncertain tax positions in any period could have a material impact on the results of operations for that period.

Investors who are in any doubt as to their tax position or who are subject to tax in jurisdictions other than the UK are strongly advised to consult their professional advisers.

Share Price Volatility and Liquidity

Although the Company is applying for the Share Capital to be admitted to trading on AIM, there can be no assurance that an active or liquid trading market for the Shares will develop or, if developed, that it will be maintained. AIM is a market designed primarily for emerging or smaller growing companies which carry a higher than normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List or some other stock exchanges. The Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List and the share price may be subject to greater fluctuations than might otherwise be the case. Accordingly, an investment in shares traded on AIM carries a higher risk than those listed on the Official List.

The Company is principally aiming to achieve capital growth and, therefore, Shares may not be suitable as a short-term investment. Consequently, the share price may be subject to greater fluctuation on small volumes of shares traded, and thus the Shares may be difficult to sell at a particular price. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market price of the Shares may not reflect the underlying value of the Company. There can be no guarantee that the value of an investment in the Company will increase. Investors may therefore realise less than, or lose all of, their original investment.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Shares are quoted and the price which investors may realise for their Shares may be influenced by a large number of factors some of which are general or market specific, others which are sector specific and others which are specific to the Company and its operations. These factors include, without limitation, (i) the performance of the Company and overall stock market, (ii) large purchases or sales of Shares by other investors, (iii) results of exploration, development and appraisal programmes and production operations, (iv) changes in analysts' recommendations and any failure by the Company to meet the expectations of the research analysts, (v) changes in legislation or regulations and changes in general economic. Political or regulatory conditions, and (vi) other factors which are outside of the control of the Company. Factors unrelated to the Company's performance could include macroeconomic developments nationally or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. Accordingly, the price at which the Shares of the Company will trade cannot be accurately predicted.

Shareholders may sell their Shares in the future to realise their investment. Sales of substantial amounts of Shares following Admission, or the perception that such sales could occur, could materially adversely affect the market price of the Shares available for sale compared to the demand to buy Shares. Such sales may also make it more difficult for the Company to sell equity securities in the future at a time and price that is deemed appropriate. There can be no guarantee that the price of the Shares will reflect their actual or potential market value or the underlying value of the Company's net assets.

In order to finance future operations or acquisition opportunities, the Company may raise funds through the issuance of Shares or the issuance of debt instruments or securities convertible into Shares. The Company cannot predict the size of future issuances of Shares or the issuance of debt instruments or other securities convertible into Shares or the effect, if any, that future issuances and sales of the Company's securities will have on the market price of the Shares.

Prices and Markets

Prices for oil and natural gas are subject to large fluctuations in response to changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic and political conditions in the United States, Canada, United Kingdom, Europe, China and other emerging markets, the actions of OPEC and other oil and gas exploring nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production or oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Company' expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Funding Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time. The Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. The Company's ability to externally finance its capital requirements is dependent on, among other factors:

- the overall state of the capital markets;
- the Company's credit rating (if applicable);
- commodity prices;

- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities in particular.

Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Reputational Risk

Any environmental damage, loss of life, injury or damage to property caused by the Company's operations could damage the Company's reputation in the areas in which the Company operates. Negative sentiment towards the Company could result in a lack of willingness of municipal authorities to grant the necessary licences or permits for the Company to operate its business and in residents in areas where the Company is doing business opposing further operations in the area by the Company. If the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Company's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Company has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Shares.

PART IV

HISTORICAL FINANCIAL INFORMATION OF THE GROUP

SECTION A: ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF THE GROUP

22 February 2019

The Directors
United Oil & Gas Plc
200 Strand
London
WC2R 1DJ

The Directors
Beaumont Cornish Limited
10th Floor
30 Crown Place
London
EC2A 4EB

Dear Sirs,

United Oil & Gas plc (the "Company")

Introduction

We report on the audited historical financial information on United Oil & Gas plc (the "Company") set out in section B (the "Company Financial Information"). This Company Financial Information has been prepared for inclusion in the admission document dated 22 February 2019 (the "AIM Admission Document") on the basis of the accounting policies set out in the Notes to the Company Financial Information. This report is required by paragraph (a) of Schedule Two to the AIM Rules for Companies (the "AIM Rules") and is given for the purposes of complying with the AIM Rules and for no other purpose.

Responsibilities

The directors of the Company are responsible for preparing the Company Financial Information in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion on the Company Financial Information as to whether the Company Financial Information gives a true and fair view, for the purposes of the Document and to report our opinion to you.

Save for any responsibility arising under Paragraph (a) of Schedule Two of the AIM Rules for Companies to any person as and to the extent there provided, to the fullest extent permitted by the law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Paragraph (a) of Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the AIM Admission Document.

We have neither audited nor reviewed the financial information for the six-month period ended 30 June 2018 which has been included for comparative purposes only and accordingly do not express an opinion thereon.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in the United States of America or other jurisdictions outside the United Kingdom and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion, the Company Financial Information gives, for the purposes of the AIM Admission Document, a true and fair view of the state of affairs of United Oil & Gas plc at 31 December 2015, 31 December 2016 and 31 December 2017, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union and that it has been prepared in a form that is consistent with the accounting policies adopted by the Company.

Declaration

For the purposes of paragraph (a) of Schedule Two of the AIM Rules for Companies, we are responsible for this report as part of the AIM Admission Document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the AIM Admission Document in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies.

Yours faithfully

UHY Hacker Young LLP

Chartered Accountants

SECTION B: HISTORICAL FINANCIAL INFORMATION OF THE GROUP

Consolidated Income Statement

	Notes	*9 months to 31 December 2015* £	*Year to 31 December 2016* £	*Year to 31 December 2017* £
Revenue		–	–	–
Cost of sales		–	–	–
Gross profit		–	–	–
Administrative expenses		(10,250)	(185,204)	(593,414)
Operating loss and loss before taxation		(10,250)	(185,204)	(593,414)
Taxation	3	–	–	–
Loss for the financial year attributable to the Company's/Group's equity shareholders		(10,250)	(185,204)	(593,414)
Earnings per share:				
Basic and diluted loss per share	4	(102.50)	(3.40)	(0.59)

Consolidated Statement of Comprehensive Income

	2015 £	*2016* £	*2017* £
Loss for the financial year	(10,250)	(185,204)	(593,414)
Foreign exchange difference	(226)	(8,117)	(26,214)
Total comprehensive income for the financial year attributable to the Company's equity shareholders	(10,476)	(193,321)	(619,628)

Consolidated Balance Sheet as at 31 December

	Notes	*2015* £	*2016* £	*2017* £
Assets				
Non-current assets				
Intangible assets	6	–	117,310	1,166,169
Property, plant and equipment	7	–	–	2,342
		–	117,310	1,168,511
Current assets				
Trade and other receivables	8	–	–	124,870
Cash and cash equivalents	9	–	75,804	3,034,968
		–	75,804	3,159,838
Total assets		–	193,114	4,328,349
Equity and liabilities				
Capital and reserves				
Share capital	10	73	259,250	2,321,850
Share premium	10	–	259,250	4,213,944
Share based payment reserve	11	–	176,099	455,493
Merger reserve	10	–	(332,712)	(2,048,084)
Translation reserve		(226)	(8,343)	(34,557)
Retained earnings		(10,250)	(195,454)	(788,868)
Shareholders' (deficit)/funds		(10,403)	158,090	4,119,778
Current liabilities:				
Trade and other payables	12	10,403	35,024	208,571
Total equity and liabilities		–	193,114	4,328,349

Consolidated Statement of Changes in Equity

	Share capital £	*Retained earnings* £	*Translation reserve* £	*Total* £
For the period ended 31 December 2015				
United Oil & Gas Ltd				
Balance at 1 April 2015	–	–	–	–
Loss for the year	–	(10,250)	–	(10,250)
Foreign exchange difference	–	–	(226)	(226)
Total comprehensive loss for the year	–	(10,250)	(226)	(10,476)
Issue of share capital in United Oil & Gas Ltd	73	–	–	73
Balance at 31 December 2015	73	(10,250)	(226)	(10,403)

	Share capital £	*Share premium* £	*Share based payments reserve* £	*Retained earnings* £	*Translation reserve* £	*Merger reserve* £	*Total* £
For the year ended 31 December 2016 UOG Holdings plc consolidated							
Balance at 1 January 2016 (United Oil & Gas Ltd)	73	–	–	(10,250)	(226)	–	(10,403)
Loss for the year	–	–	–	(185,204)	–	–	(185,204)
Foreign exchange difference	–	–	–	–	(8,117)	–	(8,117)
Total comprehensive loss for the year	–	–	–	(185,204)	(8,117)	–	(193,321)
Issue of share capital in United Oil & Gas Ltd	12,533	242,547	–	–	–	–	255,080
Redemption of share capital in United Oil & Gas Ltd	(11,766)	–	–	–	–	–	(11,766)
Effect of share for share transaction to incorporate UOG Holdings plc as parent company	199,160	(42,547)	176,099	–	–	(332,712)	–
Issue of share capital in UOG Holdings plc	59,250	59,250	–	–	–	–	118,500
Balance at 31 December 2016	259,250	259,250	176,099	(195,454)	(8,343)	(332,712)	158,090

	Share capital £	*Share premium* £	*Share based payments reserve* £	*Retained earnings* £	*Translation reserve* £	*Merger reserve* £	*Total* £
For the period ended 31 December 2017 United Oil & Gas plc consolidated							
Balance at 1 January 2017 (UOG Holdings plc)	259,250	259,250	176,099	(195,454)	(8,343)	(332,712)	158,090
Loss for the period	–	–	–	(593,414)	–	–	(593,414)
Foreign exchange difference	–	–	–	–	(26,214)	–	(26,214)
Total comprehensive loss for the year	–	–	–	(593,414)	(26,214)	–	(619,628)
Issue of share capital in UOG Holdings plc	125,000	125,000	–	–	–	–	250,000
Share issue expenses	–	(12,638)	–	–	–	–	(12,638)
Effect of combination resulting in United Oil & Gas plc becoming the parent company of the group	425,100	1,382,914	–	–	–	(1,715,372)	92,642
Share placing	1,512,500	2,737,500	–	–	–	–	4,250,000
Share issue expenses	–	(278,082)	–	–	–	–	(278,082)
Cancellation of share warrants in UOG Holdings plc	–	–	(176,099)	–	–	–	(176,099)
Issue of share warrants in United Oil & Gas plc	–	–	455,493	–	–	–	455,493
Balance at 31 December 2017	2,321,850	4,213,944	455,493	(788,868)	(34,557)	(2,048,084)	4,119,778

Consolidated Statement of Cash Flows for the year ended 31 December

	2015 £	*2016* £	*2017* £
Cash flow from operating activities			
Loss for the financial year before tax	(10,250)	(185,204)	(593,414)
Shares issued to directors in lieu of fees	–	113,798	–
Share options issued as acquisition expenses	–	–	25,377
Depreciation	–	–	452
Foreign exchange movements	–	14,668	(1,916)
	(10,250)	(56,738)	(569,501)
Changes in working capital			
Increase in trade and other receivables	–	–	(124,870)
Increase in trade and other payables	10,250	4,737	138,795
Net cash outflow from operating activities	–	(52,001)	(555,576)
Cash outflow from investing activities			
Cash acquired from United Oil & Gas plc (formerly Senterra Energy plc)	–	–	332,538
Purchase of property, plant & equipment	–	–	(2,794)
Purchase of intangible exploration assets	–	(117,310)	(1,048,859)
Net cash used in investing activities	–	(117,310)	(719,115)
Cash flow from financing activities			
Issue of ordinary shares (net of expenses)	–	259,783	4,256,862
Net cash generated from financing activities	–	259,783	4,256,862
Net increase in cash and cash equivalents	–	90,472	2,982,171
Cash and cash equivalents at beginning of financial year	–	–	75,804
Effects of exchange rate changes	–	(14,669)	(23,007)
Cash and cash equivalents at end of financial year	–	75,804	3,034,968

Notes to the consolidated historical financial information

Principal Accounting Policies

Basis of preparation

The financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"), as adopted by the European Union and, IFRIC interpretations.

The information for the year ended 31 December 2017 includes the results of United Oil & Gas plc and its subsidiaries; the information for the year ended 31 December 2016 includes the results of UOG Holdings plc and its subsidiaries; that for the year ended 31 December 2015 includes only the results of United Oil & Gas Limited.

IFRS is subject to amendment and interpretation by the IASB and the IFRS Interpretations Committee, and there is an on-going process of review and endorsement by the European Commission. These accounting policies comply with each IFRS that is mandatory for accounting periods ending on 31 December 2017.

The principal accounting policies set out below have been consistently applied to all periods presented.

Basis of consolidation

The financial information for 2017 incorporates the results of United Oil & Gas plc ("the Company") and entities controlled by the Company (its subsidiaries). Control is achieved where the Company has the power to govern the financial and operating policies of an investee entity so as to obtain benefits from its activities.

The addition of United Oil & Gas plc (formerly Senterra Energy plc) to the Group in 2017 was not accounted for as a business combination, due to the Company being considered to be a cash shell, but instead the consolidated accounts are presented as a continuation of the financial statements of the UOG Holdings plc Group, adjusted only to reflect the share capital of the new legal parent.

The addition of UOG Holdings plc to the group in 2016 was not accounted for as a business combination but instead the consolidated accounts are presented as a continuation of the financial statements of United Oil & Gas Ltd, adjusted only to reflect the share capital of the new legal parent.

All intra-Group transactions, balances, income and expenses are eliminated in full on consolidation. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Finance income and costs

Interest is recognised using the effective interest method which calculates the amortised cost of a financial asset or liability and allocates the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts or payments through the expected life of the financial asset or liability to the net carrying amount of the financial asset or liability.

Exploration and evaluation assets

The group accounts for oil and gas expenditure under the full cost method of accounting.

Costs (other than payments to acquire the legal right to explore) incurred prior to acquiring the rights to explore are charged directly to the profit and loss account. All costs incurred after the rights to explore an area have been obtained, such as geological, geophysical, data costs and other direct costs of exploration and appraisal are accumulated and capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities if technical feasibility is demonstrated and commercial reserves are discovered, then following development sanction, the carrying value of the relevant E&E asset will be reclassified as a development and production asset within tangible fixed assets.

If after completion of appraisal activities in an area, it is not possible to determine technical feasibility or commercial viability, then the costs of such unsuccessful exploration and evaluation are written off to the profit and loss account. The costs associated with any wells which are abandoned are fully amortised when the abandonment decision is taken.

Development and production assets, are accumulated generally on a field by-field basis and represent the costs of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves which have been transferred from intangible E&E assets.

The net book values of development and production assets are depreciated generally on a field-byfield basis using the unit of production method based on the commercial proven and probable reserves. Assets are not depreciated until production commences.

Property, plant and equipment

Property, plant and equipment are stated at cost on acquisition less depreciation. Depreciation is provided on a straight-line basis at rates calculated to write off the cost less the estimated residual value of each asset over its expected useful economic life. The residual value is the estimated amount that would currently be obtained from disposal of the asset if the asset were already of the age and in the condition expected at the end of its useful life.

The annual rate of depreciation for each class of depreciable asset is:

Computer equipment	33%

The carrying value of property plant and equipment is assessed annually and any impairment is charged to the income statement.

Impairment of non-financial assets

At each balance sheet date, the Directors review the carrying amounts of the Group's tangible and intangible assets, other than goodwill, to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss, if any. Where the asset does not generate cash flows that are independent from other assets, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or cash-generating unit is estimated to be less than its carrying amount, the carrying amount of the asset or cash-generating unit is reduced to its recoverable amount. If the recoverable amount of a cash-generating unit is less than its carrying amount, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit *pro rata* based on the carrying amount of each asset in the unit.

An impairment loss is recognised as an expense immediately.

An impairment loss recognised for goodwill is not reversed in subsequent periods.

Where an impairment loss subsequently reverses, the carrying amount of the asset or cash-generating unit is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset or cash-generating unit in prior periods. A reversal of an impairment loss is recognised in the Income Statement immediately.

Cash and cash equivalents

Cash and cash equivalents comprise cash in hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

Financial instruments

Financial assets and financial liabilities are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are measured initially at fair value plus transactions costs. Financial assets and financial liabilities are measured subsequently as described below.

Financial assets

The Group classifies its financial assets as 'loans and receivables'. The Group assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are classified as 'trade and other receivables' in the Balance Sheet.

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment.

A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulty, high probability of bankruptcy or a financial reorganisation and default are considered indicators that the trade receivable is impaired. The amount of the provision is the difference between the asset's carrying amount and the present value of the estimated future cash flows discounted at original effective interest rate. The loss is recognised in the Income Statement. When a trade receivable is uncollectible, it is written off against the allowance account for trade receivables. Subsequent recoveries of amounts previously written off are credited in the Income Statement.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and all substantial risks and rewards are transferred.

Financial liabilities

The Group's financial liabilities include trade and other payables.

Trade payables and borrowings are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

A financial liability is derecognised when it is extinguished, discharged, cancelled or expires.

Taxation

Current taxation for each taxable entity in the Group is based on the local taxable income at the local statutory tax rate enacted or substantively enacted at the balance sheet date and includes adjustments to tax payable or recoverable in respect of previous periods.

Deferred taxation

Deferred taxation is calculated using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial information. However, if the deferred tax arises from the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss, it is not accounted for. Deferred tax is determined using tax rates and laws that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised, or the deferred tax liability is settled.

Deferred tax liabilities are provided in full.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Changes in deferred tax assets or liabilities are recognised as a component of tax expense in the Income Statement, except where they relate to items that are charged or credited directly to equity in which case the related deferred tax is also charged or credited directly to equity.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

Foreign currency

Transactions in foreign currencies are recorded at the rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the year-end date. All differences are taken to the Income Statement.

Assets and liabilities of subsidiaries that have a functional currency different from the presentation currency (pound sterling), if any, are translated at the closing rate at the date of each balance sheet presented. Income and expenses are translated at average exchange rates. All resulting exchange differences are recognised in other comprehensive income (loss), if any.

Share based payments

Where share warrants have been granted, IFRS 2 has been applied whereby the fair value of the warrants is measured at the grant date and spread over the period during which the warrants vest. A warrants valuation model is used to assess the fair value, taking into account the terms and conditions attached to the warrants. The fair value at grant date is determined including the effect of market-based vesting conditions, to the extent such vesting conditions have a material impact.

The cost of equitysettled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled, ending on the date on which the holders become fully entitled to the award ("the vesting date").

The cumulative expense recognised for equitysettled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest.

Equity

Equity comprises the following:

- "Share capital" represents amounts subscribed for shares at nominal value.
- "Share premium" represents amounts subscribed for share capital, net of issue costs, in excess of nominal value.
- "Share based payment reserve" represents the accumulated value of share-based payments.
- "Retained earnings" represents the accumulated profits and losses attributable to equity shareholders.
- "Translation reserve" represents the exchange differences arising from the translation of the historical financial information of subsidiaries into the Group's presentational currency.
- "Merger reserve" represents amounts arising from statutory merger relief arising on business combinations.

Adoption of New and Revised International Financial Reporting Standards

At the date of authorisation of this financial information, the IASB and IFRS Interpretations Committee have issued standards, interpretations and amendments which are applicable to the Group.

Whilst these standards and interpretations are not effective for, and have not been applied in the preparation of, this financial information, the following may have an impact going forward:

Other than minor changes to standards arising from annual improvements, there have been no new or revised standards adopted in the preparation of the historical financial information for the current financial year that have had any material impact on the historical financial information of the Group.

The following EU-adopted revised or new standards have yet to be adopted by the Group. These standards will be adopted for the years ended 31 December 2018 and 31 December 2019 as shown below:

- IFRS 9 Financial Instruments (2018)
- IFRS 15 Revenue from contracts with customers (2018)
- IFRS 16 Leases (2019)

IFRS 9 'Financial Instruments' will supersede IAS 39 'Financial Instruments: Recognition and Measurement' and is effective for annual periods beginning on or after 1 January 2018. IFRS 9 covers classification and measurement of financial assets and financial liabilities, impairment of financial assets and hedge accounting.

IFRS 15 'Revenue from Contracts with Customers' provides a single model for accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations, and is effective for annual periods beginning on or after 1 January 2018. IFRS 15 will supersede IAS 18 'Revenue'.

The Group expects to adopt IFRS 9 and IFRS 15 on 1 January 2018. The Group's evaluation of the effect of adoption of these standards is ongoing but it is not currently anticipated that either IFRS 9 or IFRS 15 will have a material effect on the financial information for the Group.

IFRS 16 'Leases' provides a new model for lessee accounting in which all leases, other than short-term and small-ticket-item leases, will be accounted for by the recognition on the balance sheet of a right-to-use asset and a lease liability, and the subsequent amortisation of the right-to-use asset over the lease term. IFRS 16 will be effective for annual periods beginning on or after 1 January 2019.

The Group expects to adopt IFRS 16 on 1 January 2019. The Group's evaluation of the effect of adoption of the standard is ongoing but it is not currently expected that it will have a material effect on the Group's financial information.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the Group.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of financial information in conformity with generally accepted accounting practice requires management to make estimates and judgements that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period.

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The following are the significant judgements used in applying the accounting policies of the Group that have the most significant effect on the financial information:

Impairment of exploration licenses

Management reviews intangible exploration assets for indicators of impairment under IFRS 6 at the end of each reporting period. This review of assets for potential indicators of impairment requires judgement including whether renewal of licences is planned, interpretation of the results of exploration activity and the extent to which the Group plans to continue substantive expenditure on the assets. In determining whether substantive expenditure remains in the Group's plan, management considers factors including future oil prices, plans to develop or renew licences and future exploration plans. If impairment indicators exist the assets are tested for impairment and carried at the lower of the estimated recoverable amount and net book value.

Management did not consider there to be any impairment indicators at any reporting date presented.

Notes to the Consolidated Historical financial information

1. Segmental reporting

Operating segments

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources, assessing the performance of the operating segment and making strategic decision, has been identified as the Board of Directors. The Board of Directors consider that the Group has only one operating segment at corporate level, being the exploration and evaluation of oil and gas prospects, therefore no additional segmental information is presented.

The Group operates in three geographic areas – the UK, other EU and Latin America. The Group's revenue from external customers and information about its non-current assets (other than financial instruments, investments accounted for using the equity method, deferred tax assets and post-employment benefit assets) by geographical location are detailed below.

2015

£	*UK*	*Other EU*	*Latin America*	*Total*
Revenue	–	–	–	–
Non-current assets	–	–	–	–

2016

£	*UK*	*Other EU*	*Latin America*	*Total*
Revenue	–	–	–	–
Non-current assets	117,310	–	–	117,310

2017

£	*UK*	*Other EU*	*Latin America*	*Total*
Revenue	–	–	–	–
Non-current assets	203,805	862,712	99,652	1,166,169

2. Directors and employees

The aggregate payroll costs of the employees, including both management and Executive Directors, were as follows:

	2015 £	*2016* £	*2017* £
Staff costs			
Wages and salaries	–	16,274	200,658
Shares issued in lieu of salaries	–	110,174	–
Social security	–	2,445	1,072
	–	128,893	201,730

Average monthly number of persons employed by the Group during the year was as follows:

	2015	*2016*	*2017*
	Number	*Number*	*Number*
By activity:			
Administrative	–	–	1
Directors	2	2	3
	2	2	4

	2015	*2016*	*2017*
	£	*£*	*£*
Remuneration of Directors			
Emoluments for qualifying services	–	16,274	191,792
Shares issued in lieu of remuneration	–	110,174	–
Social security	–	2,445	–
	–	128,893	191,792

Key management personnel are identified as the Executive Directors.

No share warrants have been exercised by any of the directors, nor have any payments of pensions contributions been made on behalf of directors in any of the periods presented.

3. Taxation

	2015	*2016*	*2017*
	£	*£*	*£*
Loss before tax	(10,250)	(185,204)	(593,414)
Loss on ordinary activities multiplied by standard rate of corporation tax in the UK of 20%	(2,050)	(37,041)	(118,683)
Tax effects of:			
Unrelieved tax losses carried forward	2,050	37,041	118,683
Corporation tax charge	–	–	–

The Group has accumulated tax losses of approximately £780,000 (2016: £185,000; 2015: £10,000). No deferred tax asset was recognised in respect of these accumulated tax losses as there is insufficient evidence that the amount will be recovered in future years.

4. Earnings per share

Basic earnings per share is calculated by dividing the earnings attributable to Ordinary Shareholders by the weighted average number of Ordinary Shares outstanding during the year.

The Company/the Group did not have any potentially dilutive shares in the period ended 31 December 2015, therefore the basic and diluted earnings per share are the same.

Due to the losses incurred during the years ended 31 December 2016 and 2017, a diluted loss per share has not been calculated as this would serve to reduce the basic loss per share. There were 37,260,000 (2016: 20,000,000) share warrants outstanding at the end of the year that could potentially dilute basic earnings per share in the future.

Basic and diluted loss per share

	2015 £	2016 £	2017 £
Loss per share from continuing operations	(102.50)	(3.40)	(0.59)

The loss and weighted average number of ordinary shares used in the calculation of basic loss per share are as follows:

	2015 £	2016 £	2017 £
Loss used in the calculation of total basic and diluted loss per share	(10,250)	(185,204)	(593,414)

Number of shares

	2015 Number	2016 Number	2017 Number
Weighted average number of ordinary shares for the purposes of basic and diluted loss per share	100	5,448,224	100,814,356

5. Subsidiaries

In 2015, United Oil and Gas Limited was the only company that existed in the UOG Group.

Details of the Group's subsidiaries in 2016 and 2017 are as follows:

Name & address of subsidiary	*Principal activity*	*Class of shares*	*Place of incorporation and operation*	*% ownership held by the Group 2015*	*2016*	*2017*
UOG Holdings plc 200 Strand, London, WC2R 1DJ	Intermediate holding company	Ordinary	England and Wales	–	–	100
United Oil and Gas Limited* 9 Upper Pembroke Street, Dublin 2, Ireland	Intermediate holding company	Ordinary	Ireland	–	100	100
UOG PL090 Limited*^ 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	–	100	100
UOG Italia Srl* Viale Gioacchino Rossini 9, 00198, Rome, Italy	Oil and gas exploration	Ordinary	Italy	–	–	100
UOG Jamaica Ltd 200 Strand, London, WC2R 1DJ	Oil and gas exploration	Ordinary	England and Wales	–	–	100

*held indirectly by United Oil & Gas plc (2017)

^held indirectly by UOG Holdings plc (2016)

6. Intangible assets

	Exploration and Evaluation assets £
Cost	
At 1 April 2015	–
Additions	–
At 31 December 2015	–
Additions	117,310
At 31 December 2016	117,310
Additions	1,048,859
At 31 December 2017	1,166,169
Net book value	
At 31 December 2015	–
At 31 December 2016	117,310
At 31 December 2017	1,166,169

United Oil & Gas farmed into licences in Italy and Jamaica in the year to 31 December 2017. In July 2017 a farm in agreement was signed with PO Valley and to 31 December 2017 £862,712 has been incurred by United Oil & Gas. In November 2017 UOG farmed into the Tullow Jamaica Limited operated Walton-Morant Licences in Jamaica, for a 20% equity stake. To 31 December 2017 £99,652 has been incurred and capitalised.

The Group has continued exploration activities in Waddock Cross Licence it farmed into with Egdon Resources in 2016 and to 31 December 2017 have capitalised costs of £203,805.

Management review the intangible exploration asset for indications of impairment at each balance sheet date based on IFRS 6 criteria. Commercial reserves have not yet been established and the evaluation and exploration work is ongoing. The Directors do not consider that any indication of impairment have arisen and accordingly the assets continue to be carried at cost.

7. Property, plant and equipment

	Computer equipment £
Cost	
At 1 April 2015, 31 December 2015 & 31 December 2016	–
Additions	2,794
At 31 December 2017	2,794
Depreciation	
At 1 April 2015, 31 December 2015 & 31 December 2016	–
Charge for the year	452
At 31 December 2017	452
Net book value	
At 31 December 2015	–
At 31 December 2016	–
At 31 December 2017	2,342

Depreciation is recognised within administrative expenses.

8. Trade and other receivables

	2015 £	*2016* £	*2017* £
Unpaid share capital receivable	–	–	117,500
Prepayments	–	–	7,370
	–	–	124,870

9. Cash and cash equivalents

	2015 £	*2016* £	*2017* £
Cash at bank (GBP)	–	75,804	2,497,543
Cash at bank (EUR)	–	–	389,313
Cash at bank (USD)	–	–	148,112
	–	75,804	3,034,968

At 31 December 2015, 2016 and 2017 all significant cash and cash equivalents were deposited in the UK and Ireland with large international banks.

10. Share capital, share premium and merger reserve

Allotted, issued, and fully paid:

United Oil & Gas Ltd	*No*	*2015 Share capital £*
Ordinary shares of £0.01 each		
Opening balance	–	–
Allotments:		
1 April 2015	100	73
At 31 December 2015	100	73

UOG Holdings plc	*No*	*Share capital £*	*2016 Share premium £*
Ordinary shares of £0.01 each			
Opening balance	–	–	–
Allotments:			
1 October 2016	20,000,000	200,000	200,000
6 December 2016	5,925,000	59,250	59,250
At 31 December 2016	25,925,000	259,250	259,250

United Oil & Gas plc	*No*	*Share capital £*	*2017 Share premium £*
Ordinary shares of £0.01 each			
Opening balance	27,000,000	270,000	945,501
Allotments:			
31 July 2017	173,935,001	1,739,350	2,609,025
27 December 2017	31,250,000	312,500	937,500
Share issue costs	–	–	(278,082)
At 31 December 2017	232,185,001	2,321,850	4,213,944

Merger reserve

In the year ended 31 December 2015 the only entity that existed was United Oil & Gas Limited, therefore following the formation of UOG Holding plc during 2016, along with UOG PL090 Limited, a share for share exchange was completed whereby UOG Holdings became the parent company of United Oil and Gas Limited.

This has been presented on a merger accounting basis, therefore the results and cash flows of all the combining entities have been brought into the historical financial information of the combined entity from the beginning of the financial year in which the combination occurred with no adjustments to fair value, adjusted so as to achieve uniformity of accounting policies.

The merger reserve arising on consolidation is effectively the difference between the fair value of consideration from the share for share exchange less the net assets at the time and is calculated as follows:

Merger reserve arising in the year ended 31 December 2016:

	£
At 1 January 2016	–
Investment in United Oil and Gas Limited	576,199
United Oil and Gas Limited share capital	(940)
United Oil and Gas Limited share premium	(242,547)
At 31 December 2016	332,712

Following the reverse takeover of Senterra Energy Plc (subsequently renamed United Oil & Gas Plc) on 31 July 2017, the results of this entity have been combined with those of the UOG Holdings plc group on a merger accounting basis, however United Oil & Gas plc comparatives have not been included in prior years comparatives.

The merger reserve in the year ended 31 December 2017 is made up as follows:

Merger reserve arising in the year ended 31 December 2017:

	£	£
At 1 January 2017		332,712
Investment in UOG Holdings plc Group	1,554,810	
United Oil & Gas share capital	(384,250)	
United Oil & Gas share premium	(371,650)	
United Oil & Gas (formerly Senterra Energy plc) pre-combination retained deficit	916,462	
		1,715,372
At 31 December 2017		2,048,084

11. Share based payments

Details of the number of share warrants and the weighted average exercise price (WAEP) outstanding during the year are as follows:

2015

	Number of Warrants	*WAEP £*
Outstanding at the beginning & end of the year	–	–
Number vested and exercisable at 31 December 2015	–	–

2016

	Number of Warrants	*WAEP £*
Outstanding at the beginning of the year	–	–
Issued	20,000,000	0.02
Outstanding at the year end	20,000,000	0.02
Number vested and exercisable at 31 December 2016	20,000,000	0.02

If the warrants remain unexercised after 31 December 2021, the warrants expire.

2017

	Number of Warrants	*WAEP £*
Outstanding at the beginning of the year	20,000,000	0.02
Cancelled	(20,000,000)	(0.02)
Pre-existing warrants in United Oil & Gas	60,000	0.05
Issued	37,200,000	0.02
Outstanding at the year end	37,260,000	0.07
Number vested and exercisable at 31 December 2017	37,260,000	0.07

If the warrants remain unexercised after 31 July 2022, the warrants expire.

The fair values of share warrants issued or extended in the current financial year were calculated using the Black Scholes model as follows:

	Share warrants	*Share warrants*
Date of grant	31 July 2017	31 July 2017
Number granted	28,000,000	9,200,000
Share price at date of grant	£0.03	£0.03
Exercise price	£0.01	£0.03
Expected volatility	59%	59%
Expected life from date of grant (years)	2.5	2.5
Risk free rate	0.5555%	0.5555%
Expected dividend yield	0%	0%
Fair value/incremental fair value at date of grant	£382,533	£72,959
Earliest vesting date	31 July 2017	31 July 2017
Expiry date	31 July 2022	31 July 2022

Expected volatility was determined based on the historic volatility of a comparable company's shares for a period averaging 1 year. The expected life used in the model has been adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The Group recognised total expenses of £455,493 in relation to share warrants accounted for as equity-settled share-based payment transactions during the year (2016: £176,099; 2015: £nil). These were recognised as follows:

£382,533 (2016: £176,099; 2015: £nil) as cost of investment in subsidiary held by United Oil & Gas plc (2016: held by UOG Holdings plc) arising on the formation of the new group structure, and thus results in an increase in the merger reserve recognised in the group consolidation (see Statement of Changes in Equity).

£25,377 (2016: £nil; 2015: £nil) in relation to the combination of United Oil & Gas plc (formerly Senterra Energy plc) with the UOG Holdings plc group – recognised as expenses in the income statement.

£47,582 (2016: £nil; 2015: £nil) as a deduction from share premium related to share warrants accounted for as equity-settled share-based payment transactions during the year.

12. Trade and other payables

	2015 £	2016 £	2017 £
Trade payables	–	12,192	22,935
Tax and social security	–	998	10,694
Other payables	10,086	12,912	9,894
Deferred shares (note 13)	–	–	30,000
Accruals	317	8,922	135,048
	10,403	35,024	208,571

13. Deferred shares

On 12 October 2015, the Company issued 30,000 Deferred Shares of £1 for £30,000 to the Founder, which have an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent. of their nominal value. The Deferred Shares have no voting rights attached to them, and may be redeemed in their entirety by the Company for an aggregate redemption payment of £1.

14. Financial instruments

Categories of financial instruments

The tables below set out the Group's accounting classification of each class of its financial assets and liabilities.

Financial assets

	2015 £	2016 £	2017 £
Unpaid share capital receivable (note 8)	–	–	117,500
Cash and cash equivalents (note 9)	–	75,804	3,034,968
	–	75,804	3,152,468

All of the above financial assets' carrying values are approximate to their fair values, as at 31 December 2015, 2016 and 2017.

Financial liabilities

	Measured at amortised cost		
	2015 £	2016 £	2017 £
Trade payables (note 12)	–	12,192	22,935
Other payables (note 12)	10,086	12,912	9,894
Accruals (note 12)	317	8,922	135,048
	10,403	34,026	167,877

In the view of management, all of the above financial liabilities' carrying values approximate to their fair values as at 31 December 2015, 2016 and 2017.

Fair value measurements

This note provides information about how the Group determines fair values of various financial assets and financial liabilities.

15. Financial instrument risk exposure and management

The Group's operations expose it to degrees of financial risk that include liquidity risk, credit risk, interest rate risk.

This note describes the Group's objectives, policies and process for managing those risks and the methods used to measure them. Further quantitative information in respect of these risks is presented in notes 8, 9, 12, 14, and 16.

Liquidity risk

Liquidity risk is dealt with in note 16 of this historical financial information.

Credit risk

The Group's credit risk is primarily attributable to its cash balances.

The credit risk on liquid funds is limited because the third parties are large international banks.

The Group's total credit risk amounts to the total of cash and cash equivalents.

Interest rate risk

The Group's only exposure to interest rate risk is the interest received on the cash held on deposit, which is immaterial. The Group does not have any borrowings.

Foreign exchange risk

The Group's transactions are carried out in GBP, EUR and USD. Fundraising transactions and parent company operating transactions are carried out in GBP. Operational transactions are carried out predominantly in EUR but also in USD.

Exposures to foreign currency exchange rates arise from the Group's overseas sales and purchases, which are denominated in a number of currencies, primarily EUR and USD. Cash balances held in these currencies are relatively immaterial (see note 9) and transactional risk is considered manageable.

The Group does not hold material non-domestic balances and currently does not consider it necessary to take any action to mitigate foreign exchange risk due to the immateriality of that risk.

16. Liquidity risk

Prudent liquidity risk management includes maintaining sufficient cash balances to ensure the Group can meet liabilities as they fall due.

In managing liquidity risk, the main objective of the Group is therefore to ensure that it has the ability to pay all of its liabilities as they fall due. The Group monitors its levels of working capital to ensure that it can meet its debt repayments as they fall due. The table below shows the undiscounted cash flows on the Company's/Group's financial liabilities as at 31 December 2015, 2016 and 2017, on the basis of their earliest possible contractual maturity.

	Total £	Payable on demand £	Within 2 months £	Within 2-6 months £	Within 6-12 months £	Within 1-2 years £
At 31 December 2015						
Other payables	10,086	10,086	–	–	–	–
Accruals	317	–	–	317	–	–
	10,403	10,086	–	317	–	–

	Total £	Payable on demand £	Within 2 months £	Within 2-6 months £	Within 6-12 months £	Within 1-2 years £
At 31 December 2016						
Trade payables	12,192	–	12,192	–	–	–
Other payables	12,912	12,912	–	–	–	–
Accruals	8,922	–	–	8,922	–	–
	34,026	12,912	12,192	8,922	–	–

	Total £	Payable on demand £	Within 2 months £	Within 2-6 months £	Within 6-12 months £	Within 1-2 years £
At 31 December 2017						
Trade payables	22,935	–	22,935	–	–	–
Other payables	9,894	9,894	–	–	–	–
Accruals	135,048	–	–	135,048	–	–
	167,877	9,894	22,935	135,048	–	–

Other payables comprise loans from directors which are repayable on demand, and directors credit card liabilities.

17. Capital management

The Group's capital management objectives are:

- To ensure the Group's ability to continue as a going concern; and
- To provide long-term returns to shareholders

The Group defines and monitors capital on the basis of the carrying amount of equity less cash and cash equivalents as presented on the face of the balance sheet and as follows:

	2015 £	2016 £	2017 £
Equity	(10,403)	158,090	4,119,778
Cash and cash equivalents	–	(75,804)	(3,034,968)
	(10,403)	82,286	1,084,810

The Board of Directors monitors the level of capital as compared to the Group's commitments and adjusts the level of capital as is determined to be necessary by issuing new shares. The Group is not subject to any externally imposed capital requirements.

These policies have not changed in the period. The Directors believe that they have been able to meet their objectives in managing the capital of the Group.

18. Related party transactions

Key management personnel are identified as the Executive Directors, and their remuneration is disclosed in note 2.

Loan from director

	Brian Larkin £
Principal	
At 1 April 2015	–
Loans issued	10,086
At 31 December 2015	10,086
Loans issued	2,826
At 31 December 2016	12,912
Loans repaid	(4,352)
At 31 December 2017	8,560

The loan balance is repayable on demand with no formal terms. The load was repaid in full subsequent to the balance sheet date, in July 2018.

19. Financial commitments

As at 31 December 2015 United Oil & Gas Ltd did not have any commitments.

As at 31 December 2016, the Group had a share in an active licence, being PL090 and Waddock Cross. Annual commitments in relation to licences approximate to £20,000 of which the Group's share is approximately £4,753.

As at 31 December 2017, the Group's commitments comprise their exploration expenditure interests in Waddock Cross, Po Valley and the Walton-Morant licence. These commitments have been summarised below:

Exploration licence

	Year ending 31 December 2018 £	*Year ending 31 December 2019* £
Waddock Cross	367,071	–
Po Valley	877,867	–
Walton-Morant licence	1,655,232	355,488
	2,900,170	355,488

20. Ultimate controlling party

The directors do not consider there to be an ultimate controlling party.

21. Events after the balance sheet date

Subsequent to the balance sheet date, United Oil & Gas has announced the following:

(1) On 15 January 2018 United Oil & Gas signed an agreement to farm-in for an initial 10 per cent. interest in the Corallian Energy Limited ("Corallian") southern UK oil and gas assets. Each of the three licences are held by a joint venture between Corallian (60 per cent.) as operator and Corfe Energy Limited ("Corfe") (40 per cent.) offshore and onshore southern UK ("Initial Farmed Interest"), by way of paying 13.33 per cent. of the costs associated with the Colter well, planned for later in 2018.

Corallian and Corfe jointly hold equity in licence P1918, offshore southern UK, and onshore UK licences PEDL330 and PEDL345.

In addition, an option was granted, which expired at the end of March 2018, under which United Oil & Gas had the right to purchase an additional 10 per cent. interest in these licences on the same terms as the Initial Farmed Interest. This was not exercised.

United Oil & Gas and Corallian have also established an Area of Mutual Interest for the area, enabling the partnership to identify and target further opportunities within the same play.

(2) On 23 January 2018 a no cost option agreement to farm into offshore Block 49/29c UK Licence P2264 which contains the Acle prospect ("Option Agreement"), jointly owned by Swift Exploration Limited ("Swift") (50 per cent.) and Stelinmatvic Industries Ltd ("Stelinmatvic") (50 per cent.)

On exercise of this Option Agreement, United Oil & Gas will sign a farm-in agreement with Swift and Stelinmatvic and will acquire 24 per cent. interest in the licence, being 12 per cent. from each of Swift and Stelinmatvic. For the combined 24 per cent. interest, the Group will pay 30 per cent. of the costs associated with the drilling of the first exploration well. In addition, the Group will pay £20,000 in cash to each partner on signing of the farm-in agreement.

(3) On 20 April 2018 United Oil & Gas announced that it had conditionally raised £2.5m gross by the issue of 58,823,530 new ordinary shares in the capital of the Company at a price per share of 4.25 pence. The placing was conditional on the passing of certain shareholder resolutions at the general meeting held on 10 May 2018 and on admission, which occurred on 11 May 2018.

The Company conducted the placing in order to support the business growth of the group, and the funds have primarily been used to fund the £1m Corallian drilling costs in relation to the development of the Colter exploration well in the UK, and also for the £1.1m remaining requirements for completion of the 3D Seismic work on Colabri project under the farm-in agreement with Tullow Jamaica.

(4) On 2 August 2018, United Oil & Gas announced the issue of 11,117,647 share options to Directors and Management, with an exercise price of 4.25 pence and vesting period of 3 years from the date of grant.

(5) On 18 September 2018, United Oil & Gas announced that it had conditionally raised £3m gross via an oversubscribed placing and subscription of 54,545,454 new ordinary shares of 1p each in the capital of the Company at a price of 5.5 pence per placing share. The placing was conditional on the passing of certain shareholder resolutions at the general meeting held on 8 October 2018 and on admission, which occurred on 10 October 2018.

September 2018 Placees also received a total of 40,909,080 warrants over ordinary shares in the Company, on the basis of 3 warrants, exercisable at 8 pence per share, for every 4 placing shares, rounded down to the nearest warrant. The warrants have a 4-year life and are exercisable from the first anniversary of issue. The warrants are not listed.

(6) On 13 November 2018, United Oil & Gas issued an update on the Colter appraisal well ('the Well') on P1918 in the Wessex Basin. United Oil & Gas holds a 10 per cent. interest in the Well, which is operated by Corallian Energy.

The Department for Business, Energy and Industrial Strategy, Offshore Petroleum Regulator for Environment and Decommissioning ('OPRED') has completed its review of the Environmental

Statement ('ES'), the representations received from consultees and additional information provided for the Colter well. Based on this review, OPRED has advised the Oil and Gas Authority ('OGA') of its in-principle agreement to the issue of the relevant consent for the Well.

Corallian Energy commenced the drilling of the Colter well on 6 February 2019 which is expected to take three weeks.

Colter will appraise a historic discovery that lies immediately to the south of Europe's largest onshore oil field at Wytch Farm. The discovery was made in 1986 by well 98/11-3, which encountered a 10.5m oil column in the Sherwood Sandstone reservoir, the same play that has proven to be so productive at Wytch Farm where over 450mmbbls have been produced to date. The new well will be drilled updip of 98/11-3 targeting significant potential that has been identified following reprocessing of 3D seismic data. The gross unrisked mid-case oil contingent resources in the section proven up by the 98/11-3 well have been estimated at 4mmbbls, with gross unrisked mean-case prospective resources estimated at 15mmbbls in the rest of the structure.

SECTION C: UNAUDITED HALF-YEARLY RESULTS

CONSOLIDATED INCOME STATEMENT

	Note	*Six months ended 30 June 2017 Unaudited* £	*Six months ended 30 June 2018 Unaudited* £
Revenue		–	–
Cost of sales		–	–
Gross profit		–	–
Administrative expenses		(129,355)	(438,801)
Operating loss and loss before taxation		(129,355)	(438,801)
Taxation		–	–
Loss for the financial period attributable to the Company's/Group's equity shareholders		(129,355)	(438,801)
Loss per share from continuing operations expressed in pence per share:			
Basic and diluted	3	(0.36)	(0.18)

Consolidated statement of comprehensive loss

	Six months ended 30 June 2017 Unaudited £	*Six months ended 30 June 2018 Unaudited* £
Loss for the financial period	(129,355)	(438,801)
Foreign exchange difference	(1,791)	45,149
Loss for the financial period attributable to the Company's/Group's equity shareholders	(131,146)	(393,652)

CONSOLIDATED BALANCE SHEET
At 30 June 2018

	Note	*31 December 2017 Audited* £	*30 June 2018 Unaudited* £
Assets			
Non-current assets			
Intangible assets	4	1,166,169	3,674,998
Property, plant and equipment		2,342	2,735
		1,168,511	3,677,733
Current assets			
Trade and other receivables		124,870	7,529
Cash and cash equivalents		3,034,968	2,405,189
		3,159,838	2,412,718
Total assets		4,328,349	6,090,451
Equity and liabilities			
Capital and reserves			
Share capital	5	2,321,850	2,910,685
Share premium	5	4,213,944	5,776,177
Share-based payment reserve		455,493	455,493
Merger reserve		(2,048,084)	(2,048,084)
Translation reserve		(34,557)	10,592
Retained earnings		(788,868)	(1,227,669)
Shareholders' funds		4,119,778	5,877,194
Current liabilities			
Trade and other payables		208,571	213,257
Total liabilities		208,571	213,257
Total equity and liabilities		4,328,349	6,090,451

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

Six months ended 30 June 2018

	Share capital £	*Share premium* £	*Share based payments reserve* £	*Retained earnings* £	*Translation reserve* £	*Merger reserve* £	*Total equity* £
For the period ended 30 June 2017							
Balance at 1 January 2017 (UOG Holdings plc)	259,250	259,250	176,099	(195,454)	(8,343)	(332,712)	158,090
Loss for the period	–	–	–	(129,355)	–	–	(129,355)
Foreign exchange difference	–	–	–	–	(1,791)	–	(1,791)
Total comprehensive loss for the period	–	–	–	(129,355)	(1,791)	–	(131,146)
Issue of share capital in UOG Holdings plc	125,000	125,000	–	–	–	–	250,000
Share issue expenses	–	(12,600)	–	–	–	–	(12,600)
Balance at 30 June 2017 (Unaudited)	384,250	371,650	176,099	(324,809)	(10,134)	(332,712)	264,344
For the period ended 30 June 2018							
Balance at 1 January 2018	2,321,850	4,213,944	455,493	(788,868)	(34,557)	(2,048,084)	4,119,778
Loss for the period	–	–	–	(438,801)	–	–	(438,801)
Foreign exchange difference	–	–	–	–	45,149	–	45,149
Total comprehensive loss for the period	–	–	–	(438,801)	45,149	–	(393,652)
Issue of shares on exercise of warrants	600	2,400	–	–	–	–	3,000
Issue of shares	588,235	1,911,765	–	–	–	–	2,500,000
Expenses of issue	–	(351,932)	–	–	–	–	(351,932)
Balance at 30 June 2018 (Unaudited)	2,910,685	5,776,177	455,493	(1,227,669)	10,592	(2,048,084)	5,877,194

CONSOLIDATED STATEMENT OF CASHFLOWS
Six months ended 30 June 2018

	Six months ended 30 June 2017 Unaudited £	*Six months ended 30 June 2018 Unaudited* £
Cash flows from operating activities		
Loss for the financial period before taxation	(129,355)	(438,801)
Adjustments for:		
Depreciation	101	491
	(129,254)	(438,310)
Decrease in trade and other receivables	–	117,341
Increase in trade and other payables	17,215	4,683
Net cash outflow from operating activities	(112,039)	(316,286)
Cash flows from investing activities		
Purchase of property, plant & equipment	(1,371)	(885)
Exploration and evaluation expenditure	(98,603)	(2,508,829)
Net cash used in investing activities	(99,974)	(2,509,714)
Cash flows from financing activities		
Issue of ordinary shares (net of expenses)	237,400	2,151,068
Net cash generated from financing activities	237,400	2,151,068
Increase/(decrease) in cash and cash equivalents	25,387	(674,932)
Cash and cash equivalents at beginning of period	75,804	3,034,968
Effects of exchange rate changes	(1,792)	45,153
Cash and cash equivalents at end of period	99,399	2,405,189

Notes to the financial information
Period ended 30 June 2018

1. Accounting policies

The consolidated interim financial information in this report has been prepared on the basis of the accounting policies set out in the consolidated financial information for the years ended 31 December 2016 and 2017, which complied with International Financial Reporting Standards as adopted for use in the European Union ("IFRS"). The financial information for the periods ended 30 June 2017 and 30 June 2018 is unaudited.

The results for the period ended 30 June 2018 and as at 31 December 2017 include the results of United Oil & Gas plc and its subsidiaries; those for the period ended 30 June 2017 include the results of UOG Holdings plc and its subsidiaries.

IFRS is subject to amendment and interpretation by the International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee and there is an on-going process of review and endorsement by the European Commission.

The financial information has been prepared on the basis of IFRS that the Directors expect to be applicable as at 31 December 2018.

Exploration and evaluation assets

The group accounts for oil and gas expenditure under the full cost method of accounting.

Costs (other than payments to acquire the legal right to explore) incurred prior to acquiring the rights to explore are charged directly to the profit and loss account. All costs incurred after the rights to explore an area have been obtained, such as geological, geophysical, data costs and other direct costs of exploration and appraisal are accumulated and capitalised as intangible exploration and evaluation ("E&E") assets.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities if technical feasibility is demonstrated and commercial reserves are discovered, then following development sanction, the carrying value of the relevant E&E asset will be reclassified as a development and production asset within tangible fixed assets.

If after completion of appraisal activities in an area, it is not possible to determine technical feasibility or commercial viability, then the costs of such unsuccessful exploration and evaluation are written off to the profit and loss account. The costs associated with any wells which are abandoned are fully amortised when the abandonment decision is taken.

Development and production assets, are accumulated generally on a field by-field basis and represent the costs of developing the commercial reserves discovered and bringing them into production, together with the E&E expenditures incurred in finding commercial reserves which have been transferred from intangible E&E assets.

The net book values of development and production assets are depreciated generally on a field-byfield basis using the unit of production method based on the commercial proven and probable reserves. Assets are not depreciated until production commences.

2. Related party transactions

The directors are considered to be the key management personnel of the company. During the interim period, the company paid fees to directors amounting to £148,708 (Period ended 30 June 2017 – £18,000).

During the June 2017 interim period, the company was charged fees and commission of £12,000 by Optiva Securities Limited, a company in which the former director, J King, is a director and shareholder.

3. Loss per share

Basic loss per share is calculated by dividing the loss attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the period.

Given the Group's reported loss for the period, share options and warrants are not taken into account when determining the weighted average number of ordinary shares in issue during the year as they would be anti-dilutive, and therefore the basic and diluted loss per share are the same.

Basic and diluted loss per share

	Period ended 30 June 2017	*Period ended 30 June 2018*
Loss for the period (£)	(129,355)	(438,801)
Weighted average number of ordinary shares (number)	36,284,116	248,798,040
Loss per share from continuing operations (pence per share)	(0.36)	(0.18)

4. Intangible assets

	Exploration and Evaluation assets £
Cost	
At 31 December 2016	117,310
Additions	1,048,859
At 31 December 2017	1,166,169
Additions	2,508,829
At 30 June 2018	3,674,998
Net book value	
At 31 December 2017	1,166,169
At 30 June 2018	3,674,998

United Oil & Gas farmed into a UK licence in the Wessex basin with Corallian Energy Limited in January 2018, in which the Colter well is to be drilled in Q12019 The costs incurred and capitalised to 30 June 2018 are £143,331, primarily consisting of initial well preparation costs to the Operator.

In May 2018 United Oil & Gas was awarded two blocks in the UK North Sea's 30th licencing round, which includes the Crown discovery and to 30 June 2018 the Company has incurred £7,400. A work programme will be finalised in Q3 of this year. Early licence costs to date consist of internal timewriting.

In Italy well drilling and testing was completed at Podere Gallina in the first quarter of 2018. To 30 June 2018 the company has capitalised costs of £1,875,620 of which £1,012,878 were in 2018 consisting of final payments on drilling and well testing to Po Valley as operator, along with some consulting and professional fees incurred. Development activities are on track for 2019.

Jamaica activity consisted primarily of the 3D Seismic acquisition on the Walton-Morant licence with our partners Tullow Oil, and to 30 June 2018 United Oil & Gas have capitalised costs of £1,398,574 of which £1,298,922 was spent in 2018.

Activities have continued on our UK asset with Egdon Resources on the Waddock Cross licence and to 30 June 2018 the company have capitalised costs of £250,073, of which £46,298 was incurred in the first half of 2018. The first well to be drilled is still targeted for H1 2019.

Management review the intangible exploration assets for indications of impairment at each balance sheet date based on IFRS 6 criteria. Commercial reserves have not yet been established and the evaluation and exploration work is ongoing. The Directors do not consider that any indication of impairment have arisen and accordingly the assets continue to be carried at cost.

5. Share capital & share premium

Allotted, issued, and fully paid:

			30 June 2018
		Share capital	*Share premium*
United Oil & Gas plc	*No*	£	£
Ordinary shares of £0.01 each			
Opening balance	232,185,001	2,321,850	4,213,944
Allotments:			
7 March 2018	60,000	600	2,400
11 May 2018	58,823,530	588,235	1,911,765
Share issue costs	–	–	(351,932)
At 30 June	291,068,531	2,910,685	5,776,177

			31 December 2017
		Share capital	*Share premium*
United Oil & Gas plc	*No*	£	£
Ordinary shares of £0.01 each			
Opening balance	27,000,000	270,000	945,501
Allotments:			
31 July 2017	173,935,001	1,739,350	2,609,025
27 December 2017	31,250,000	312,500	937,500
Share issue costs	–	–	(278,082)
At 31 December	232,185,001	2,321,850	4,213,944

6. Events after the Balance Sheet Date

(1) On 2 August 2018, United Oil & Gas issued 11,117,647 share options to Directors and Management, with an exercise price of 4.25 pence and vesting period of 3 years from the date of grant.

(2) On 18 September 2018, United Oil & Gas announced that it had conditionally raised £3m gross via an oversubscribed placing and subscription of 54,545,454 new ordinary shares of 1p each in the capital of the Company at a price of 5.5 pence per placing share. The placing was conditional on the passing of certain shareholder resolutions at the general meeting held on 8 October 2018 and on admission, which occurred on 10 October 2018.

September 2018 Placees also received a total of 40,909,080 warrants over ordinary shares in the Company, on the basis of 3 warrants, exercisable at 8 pence per share, for every 4 placing shares, rounded down to the nearest warrant. The warrants have a 4-year life and are exercisable from the first anniversary of issue. The warrants are not listed.

(3) On 13 November 2018, United Oil & Gas issued an update on the Colter appraisal well ('the Well') on P1918 in the Wessex Basin. United Oil & Gas holds a 10 per cent. interest in the Well, which is operated by Corallian Energy.

The Department for Business, Energy and Industrial Strategy, Offshore Petroleum Regulator for Environment and Decommissioning ('OPRED') has completed its review of the Environmental Statement ('ES'), the representations received from consultees and additional information provided for the Colter well. Based on this review, OPRED has advised the Oil and Gas Authority ('OGA') of its in-principle agreement to the issue of the relevant consent for the Well.

Corallian Energy commenced the driling of the Colter well on 6 February 2019 which is expected to take three weeks.

Colter will appraise a historic discovery that lies immediately to the south of Europe's largest onshore oil field at Wytch Farm. The discovery was made in 1986 by well 98/11-3, which encountered a 10.5m oil column in the Sherwood Sandstone reservoir, the same play that has proven to be so productive at Wytch Farm where over 450mmbbls have been produced to date. The new well will be drilled updip of 98/11-3 targeting significant potential that has been identified following reprocessing of 3D seismic data. The gross unrisked mid-case oil contingent resources in the section proven up by the 98/11-3 well have been estimated at 4mmbbls, with gross unrisked mean-case prospective resources estimated at 15mmbbls in the rest of the structure.

PART V

PRO FORMA NET ASSETS

SECTION A: PRO FORMA NET ASSETS

Set out below is an unaudited pro forma statement of net assets of United Oil & Gas plc as at 30 June 2018 for the six months ended 30 June 2018. The unaudited pro forma statement of net assets have been prepared for illustrative purposes only to illustrate the effect on the net assets of United Oil & Gas plc of the admission, and certain other subsequent events as described in the notes below, as if they had taken place as at 30 June 2018. Because of the nature of pro forma financial information, this unaudited pro forma statement of net assets addresses a hypothetical situation and does not therefore represent the actual financial position and statement of earnings of United Oil & Gas plc as at 30 June 2018. The unaudited pro forma statement of net assets has been prepared on the basis described in the notes set out below and after making the adjustments described in those notes.

Unaudited Pro Forma Statement of Net Assets of United Oil & Gas plc

	The Company at 30 June 2018 Note 1	*Shares issued Note 2*	*AIM admission expenses Note 3*	*Pro forma net assets (unaudited)*
	£	£	£	£
ASSETS				
Non-current assets				
Intangible assets	3,674,998	–	–	3,674,998
Property, plant and equipment	2,735	–	–	2,735
Total non-current assets	3,677,733	–	–	3,677,733
Current assets				
Trade and other receivables	7,529	–	–	7,529
Cash and cash equivalents	2,405,189	2,777,164	(252,500)	4,929,853
Total current assets	2,412,718	2,777,164	(252,500)	4,937,382
TOTAL ASSETS	6,090,451	2,777,164	(252,500)	8,615,115
Current liabilities				
Trade and other payables	213,257	–	–	213,257
Deferred shares	–	–	–	–
Total current liabilities	213,257	–	–	213,257
NET ASSETS	5,877,194	2,777,164	(252,500)	8,401,858

Notes:

1. The financial information for United Oil & Gas plc has been extracted without adjustment from the historical financial information as at 30 June 2018.
2. On 18 September, United Oil & Gas announced that it had conditionally raised £3 million gross via an oversubscribed placing and subscription of 54,545,454 new ordinary shares of 1p each in the capital of the Company at a price of 5.5 pence per Placing Share net of expenses of £222,836. The placing was conditional on the passing of certain shareholder resolutions at the General Meeting held on 8 October 2018 and on Admission, which occurred on 10 October 2018.
3. On the admission to AIM the estimated expenses of Admission are £252,500.

SECTION B: ACCOUNTANT'S REPORT ON THE PRO FORMA NET ASSETS

22 February 2019

The Directors
United Oil & Gas Plc
200 Strand
London
WC2R 1DJ

The Directors
Beaumont Cornish Limited
10th Floor
30 Crown Place
London
EC2A 4EB

Dear Sirs,

United Oil & Gas plc (the "company")

Pro forma financial information

We report on the unaudited pro forma statements of net assets as at 30 June 2018 of United Oil & Gas plc ("the Company") (the "Unaudited Pro Forma Financial Information") set out in section A of this Part V of the admission document dated 22 February 2019 of the company (the "AIM Admission Document") which has been prepared on the basis described, for illustrative purposes only, to provide information about how the AIM admission and certain other subsequent events might have affected the financial information presented on the basis of accounting policies adopted by the Company in preparing the historical financial information for the six-months ended 30 June 2018.

Responsibilities

This report is as agreed between us in writing and is given for the purpose of complying with that requirement and for no other purpose.

Save for any responsibility that we have expressly agreed to in writing to assume, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report.

It is the responsibility of the Directors of the Company to prepare the pro forma financial information, which has been prepared in accordance with Schedule Two of the AIM Rules for Companies with reference to paragraph 20.2 of Annex I of the Prospectus Rules attached to the AIM Rules for Companies as if it had been applicable.

It is our responsibility to form an opinion, which would have been required by paragraph 7 of Annex II of the Prospectus Rules attached to the AIM Rules for Companies as to the proper compilation of the pro forma financial information and to report that opinion to you.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro forma financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussion the Pro Forma Financial Information with the Directors.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing standards generally accepted in the United Kingdom and accordingly should not be relied upon as if it had been carried out in accordance with those standards.

Opinion

In our opinion:

(a) The Pro Forma Financial Information has been properly compiled on the basis stated; and

(b) Such basis is consistent with the accounting policies of the Company.

Declaration

For the purposes of Paragraph (a) of Schedule Two of the AIM Rules for Companies we are responsible for this report as part of the AIM Document and declare that we have taken all reason able care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely affect its import. This declaration is included in the AIM Document in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies

Yours faithfully

UHY Hacker Young

Chartered Accountants

PART VI

TAXATION

The following section is a summary guide only to certain aspects of tax in the UK. This is not a complete analysis of all the potential tax effects of acquiring, holding and disposing of Ordinary Shares, nor will it relate to the specific tax position of all Shareholders in all jurisdictions. This summary is not a legal opinion. Shareholders are advised to consult their own tax advisers.

1. Taxation in the United Kingdom

The following information is based on UK tax law and HM Revenue and Customs ("**HMRC**") practice currently in force in the UK. Such law and practice (including, without limitation, rates of tax) is in principle subject to change at any time. The information that follows is for guidance purposes only. Any person who is in any doubt about his or her position should contact their professional adviser immediately.

1.1 *Tax treatment of UK investors*

The following information, which relates only to UK taxation, is applicable to persons who are resident in the UK and who beneficially own Ordinary Shares as investments and not as securities to be realised in the course of a trade. It is based on the law and practice currently in force in the UK. The information is not exhaustive and does not apply to potential investors:

(i) who intend to acquire, or may acquire (either on their own or together with persons with whom they are connected or associated for tax purposes), more than 10 per cent., of any of the classes of shares in the Company; or

(ii) who intend to acquire Ordinary Shares as part of tax avoidance arrangements; or

(iii) who are in any doubt as to their taxation position.

Such Shareholders should consult their professional advisers without delay. Shareholders should note that tax law and interpretation can change and that, in particular, the levels, basis of and reliefs from taxation may change. Such changes may alter the benefits of investment in the Company.

Shareholders who are neither resident nor temporarily non-resident in the UK and who do not carry on a trade, profession or vocation through a branch, agency or permanent establishment in the UK with which the Ordinary Shares are connected, will not normally be liable to UK taxation on dividends paid by the Company or on capital gains arising on the sale or other disposal of Ordinary Shares. Such Shareholders should consult their own tax advisers concerning their tax liabilities.

1.2 *Dividends*

Where the Company pays dividends, Shareholders who are resident in the UK for tax purposes will, depending on their circumstances, be liable to UK income tax or corporation tax on those dividends.

UK resident individual Shareholders who are domiciled in the UK, and who hold their Ordinary Shares as investments, will be subject to UK income tax on the amount of dividends received from the Company.

Dividend income received by UK tax resident individuals will have a £2,000 dividend tax allowance. Dividend receipts in excess of £2,000 will be taxed at 7.5 per cent. for basic rate taxpayers, 32.5 per cent. for higher rate taxpayers, and 38.1 per cent. for additional rate taxpayers

Shareholders who are subject to UK corporation tax should generally, and subject to certain anti-avoidance provisions, be able to claim exemption from UK corporation tax in respect of any dividend received but will not be entitled to claim relief in respect of any underlying tax or withholding tax imposed.

1.3 Disposals of Ordinary Shares

Any gain arising on the sale, redemption or other disposal of Ordinary Shares will be taxed at the time of such sale, redemption or disposal as a capital gain.

The rate of capital gains tax on disposal of Ordinary Shares by basic rate taxpayers is 10 per cent., and for upper rate and additional rate taxpayers the rate is 20 per cent.

For Shareholders within the charge to UK corporation tax, the corporation tax rate applicable to its taxable profits is 19 per cent. It was proposed in 16 March 2016 budget that the rate of corporation tax after 1 April 2020 will fall to 17 per cent.

1.4 ***Further information for Shareholders subject to UK income tax and capital gains tax "Transactions in securities"***

The attention of Shareholders (whether corporates or individuals) within the scope of UK taxation is drawn to the provisions set out in, respectively, Part 15 of the Corporation Tax Act 2010 and Chapter 1 of Part 13 of the Income Tax Act 2007, which (in each case) give powers to HM Revenue and Customs to raise tax assessments so as to cancel "tax advantages" derived from certain prescribed "transactions in securities".

1.5 ***Stamp Duty and Stamp Duty Reserve Tax ("SDRT")***

The statements below are intended as a general guide to the current position. They do not apply to certain intermediaries who are not liable to stamp duty or SDRT or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

1.5.1 *Ordinary Shares held in certificated form*

No UK stamp duty or SDRT will be payable on the issue of the Ordinary Shares. Most investors will purchase existing Ordinary Shares using the CREST paperless clearance system and these acquisitions will be subject to SDRT at 0.5 per cent. Where Ordinary Shares are acquired using paper (i.e. non-electronic settlement) stamp duty will become payable if the purchase consideration exceeds £1,000.

This summary of UK taxation issues can only provide a general overview of these areas and it is not a description of all the tax considerations that may be relevant to a decision to invest in the Company. The summary of certain UK tax issues is based on the laws and regulations in force as of the date of this Document and may be subject to any changes in UK law occurring after such date. Legal advice should be taken with regard to individual circumstances. Any person who is in any doubt as to his or her tax position or where he or she is resident, or otherwise subject to taxation, in a jurisdiction other than the UK, should consult his or her professional adviser.

PART VII

ADDITIONAL INFORMATION

1. RESPONSIBILITY STATEMENT

1.1 The Company and the Directors accept responsibility for the information contained in this Document, including individual and collective responsibility, and for the Company's compliance with the AIM Rules for Companies. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.2 UHY Hacker Young LLP, whose address appears on page 7 of this Document, accepts responsibility for the information contained in Parts IV through V of this Document. To the best of the knowledge and belief of UHY Hacker Young LLP (who have taken all reasonable care to ensure that such is the case) the information contained in Parts IV through V of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.3 ERC Equipoise Ltd, whose address appears on page 8 of this Document, accepts responsibility for the information contained in Part VIII of this Document. To the best of the knowledge and belief of ERC Equipoise Ltd (who has taken all reasonable care to ensure that such is the case) the information contained in Part VIII of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

1.4 CGG Service (UK) Limited, whose address appears on page 8 of this Document, accepts responsibility for the information contained in Part IX of this Document. To the best of the knowledge and belief of CGG Service (UK) Limited (who have taken all reasonable care to ensure that such is the case) the information contained in Part IX of this Document is in accordance with the facts and makes no omission likely to affect the import of such information.

2. INCORPORATION AND STATUS OF THE COMPANY

2.1 The Company was incorporated and registered in England and Wales as a company limited by shares on 5 June 2015 under the Act, with the name Senterra Energy Limited and with registered number 09624969. On 15 October 2015, the Company was re-registered as a public limited company under the legal and commercial name Senterra Energy plc. On 28 July 2017 the Company changed its legal and commercial name to United Oil & Gas Plc. The Company is domiciled in England.

2.2 The liability of the members of the Company is limited.

2.3 The principal legislation under which the Company operates is the Act and the regulations made thereunder.

2.4 The registered office of the Company is at 200 Strand, London WC2R 1DJ.

2.5 The telephone number of Company is +353 1 9053557.

3. THE SUBSIDIARIES

3.1 The Company acts as the ultimate holding company of the Group.

3.2 The Company has the following direct subsidiary which is a public limited company:

Name	*Country of incorporation*	*Registered office*	*Proportion of ownership interest*	*Principal activity*
UOG Holdings PLC	England and Wales	200 Strand, London WC2R 1DJ	100%	Holding Company

3.3 The Company has the following indirect subsidiaries which are private limited companies:

Name	*Country of incorporation*	*Registered office*	*Proportion of ownership interest*	*Principal activity*
UOG Ireland Limited	Ireland	9 Upper Pembroke Street, Dublin 2	100%	Holding Company
UOG PL090 Limited	England and Wales	200 Strand, London WC2R 1DJ	100%	Oil and gas exploration and production
UOG Italia S.r.l	Italy	Viale Gioacchnio, Rossini 9, Cap 00198, Rome	100%	Oil and gas exploration and production
UOG Jamaica Limited	England and Wales	200 Strand, London WC2R 1DJ	100%	Oil and gas exploration and production
UOG Colter Limited	England and Wales	200 Strand, London WC2R 1DJ	100%	Oil and gas exploration and production
UOG Crown Limited	England and Wales	200 Strand, London WC2R 1DJ	100%	Oil and gas exploration and production

4. SHARE CAPITAL OF THE COMPANY

4.1 The issued share capital of the Company, at the date of this Document and immediately following Admission, is and will be as follows:

	Number of Ordinary Shares issued and credited as fully paid (£)	*Number of Ordinary Shares*
At the date of this Document	3,456,139	345,613,985
On Admission	3,456,139	345,613,985

4.2 The Company was incorporated on 5 June 2015 with an issued share capital of £1 consisting of one ordinary share of £1 which was allotted to the Founder. On 12 October 2015, the Company issued and allotted to the Founder 19,999 additional ordinary shares of £1 each for a total subscription price of £19,999, together with 30,000 Deferred Shares for a total subscription price of £30,000.The Deferred Shares, whose rights are described in paragraph 4.3 below, have negligible value and were subscribed by the Founder to satisfy the minimal nominal capital requirement of £50,000 for UK public companies.

4.3 The Deferred Shares, issued to the Founder, each confer an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent. of their nominal value (equivalent to an aggregate dividend payment of £30 on all the Deferred Shares which is first payable on the first anniversary of their issue (being 5 June 2016) and annually thereafter). The Deferred Shares carry no further right to participate in the profits or assets of the Company and carry no Voting Rights. They may all be redeemed by the Company for an aggregate redemption payment of £1.

4.4 On 12 October 2015, the Company subdivided each ordinary share of £1 into 100 ordinary shares of £0.01 each.

4.5 On 4 November 2015, a further 25,000,000 Ordinary Shares were conditionally allotted and issued pursuant to a placing at a price of 5 pence per Ordinary Share.

4.6 On 24 July 2017, the Company conditionally allotted and issued 120,000,000 Ordinary Shares to placees at 2.5p per share.

4.7 On 31 July 2017, the Company issued 53,935,001 Ordinary Shares to the Vendors and 28,000,000 Warrants under the UOG Warrant Instrument.

4.8 On 27 December 2017, a further 31,250,000 Ordinary Shares were allotted at a price of 4 pence per Ordinary Share.

4.9 On 2 March 2018, 60,000 Ordinary Shares were issued to Dowgate as a result of the exercise in full of Warrants granted to it by the Company.

4.10 On 11 May 2018, 58,823,530 Ordinary Shares were issued at a placing price of 4.25 pence per Ordinary Share pursuant to a placing.

4.11 On or about 2 August 2018, the Company granted Options over an aggregate number of 11,117,648 Ordinary Shares to the Directors and the Finance Manager as set out in the table below.

Name	*No. of Options*
Brian Larkin	4,235,294
Jonathan Leather	4,058,824
Graham Martin	1,176,471
Alberto Cattaruzza	352,941
Rodney Mooney	1,294,118

The Options vest three years from the date of grant, have an expiry date of ten years from the date of vesting and are exercisable at a price of 4.25 pence per Ordinary Share. The Options are only exercisable if the optionholder is employed by the Company and he has not served, or has had served upon him by the Company, notice to terminate his employment or appointment at the time of exercise.

4.12 On 10 October 2018, a further 54,545,454 Ordinary Shares were allotted and issued at a price of 5.5 pence per Ordinary Share pursuant to a placing.

4.13 ***Warrants***

The table below sets outstanding existing Warrants at the date of the Document:

Instrument	*Latest exercise date*	*Number*	*Exercise*	*Exercise Period*
UOG Warrant Instrument	31 July 2022	28,000,000*	1.42857p	31 July 2017 to 31 July 2022
Beaumont Cornish Warrant Instrument	31 July 2022	3,200,000	2.5p	31 July 2017 to 31 July 2022
Optiva Warrant Instrument	31 July 2020	6,000,000	2.5p	31 July 2017 to 31 July 2020
Optiva December 2017 Warrant Instrument	27 December 2022	1,375,000	4p	27 December 2017 to 27 December 2022
Optiva April 2018 Warrant Instrument	27 December 2022	2,728,126	4.25p	27 December 2017 to 27 December 2022
September 2018 Warrant Instrument	10 October 2023	40,909,080	8p	10 October 2019 to 10 October 2023

*these warrants have been issued to certain Vendors (further details of which are set out in paragraph 11.17).

4.14 The Articles were adopted by the Company pursuant to a special resolution passed on 12 October 2015, the principal terms of which are summarised in paragraph 5 of this Part VII.

4.15 No Ordinary Shares are currently in issue with a fixed date on which entitlement to a dividend arises and there are no arrangements in force whereby future dividends are waived or agreed to be waived.

4.16 Save as disclosed in this Part VII:

4.16.1 no share or loan capital of the Company has been issued or is proposed to be issued, fully or partly paid, either for cash or for a consideration other than cash;

4.16.2 no share or loan capital of the Company is under option or is the subject of an agreement, conditional or unconditional, to be put under option; and

4.16.3 no commission, discounts, brokerage or other special term has been granted by the Company or is now proposed in connection with the issue or sale of any part of the share or loan capital of the Company.

5. ARTICLES OF ASSOCIATION

5.1 The following is a description of the rights attaching to the Ordinary Shares based on the Articles and English law. This description does not purport to be complete and is qualified in its entirety by the full terms of the Articles.

5.1.1 ***Voting***

Subject to any rights or restrictions attaching to any class of shares, every member present in person at a general meeting or class meeting has, upon a show of hands, one vote, and every member (excluding any member holding shares as treasury shares) present in person or by proxy has, upon a poll, one vote for every share held by him. The Deferred Shares carry no voting rights.

In the case of joint holders of a share the vote of the senior who tenders a vote, whether in person or by proxy, shall be accepted to the exclusion of the votes of the other joint holders and, for this purpose, seniority shall be determined by the order in which the names stand in the register in respect of the joint holding.

5.1.2 ***Dividends and other distributions***

The profits of the Company available for dividend in accordance with the Act and determined to be distributed shall be applied in the payment of dividends to the members in accordance with their respective rights and priorities. The Company may by ordinary resolution declare dividends accordingly. Subject to the rights of persons (if any) entitled to ordinary shares with special rights as to dividend, all dividends shall be declared and paid according to the amounts paid up on the Ordinary Shares in respect whereof the dividends are paid, but no amount paid up on a share in advance of calls shall be treated as paid up on the Ordinary Shares; all dividends shall be apportioned and paid *pro rata* according to the amounts paid up on the Ordinary Shares during any portion or portions of the period in respect of which the dividend is paid, except that if any share is issued on terms providing that it shall rank for dividend as if paid up (in whole or in part) as from a particular date such share shall rank for dividend accordingly. The Deferred Shares carry a dividend entitlement as described below in this paragraph.

The Company may by ordinary resolution from time to time declare dividends not exceeding the amount recommended by the Board. Subject to the Act, the Board may pay interim dividends, and also any fixed rate dividend, whenever the financial position of the Company, in the opinion of the Board, justifies its payment. If the Board acts in good faith, it is not liable to holders of shares with preferred or *pari passu* rights for losses arising from the payment of interim or fixed dividends on other shares. There are no fixed dates for the payment of dividends, except as described below.

The Board may withhold payment of all or any part of any dividends or other moneys payable in respect of the Company's shares from a person with a 0.25 per cent. interest if such a person has been served with a direction notice (as defined in the Articles) after failure to provide the Company with information concerning interests in those shares required to be provided under the Act.

Except insofar as the rights attaching to, or the terms of issue of, any share otherwise provide, all dividends shall be apportioned and paid *pro rata* according to the amounts paid up on the share during any portion of the period in respect of which the dividend is paid. Except as set out above, dividends may be declared or paid in any currency.

The Board may, if authorised by an ordinary resolution of the Company, offer ordinary Shareholders (excluding any member holding shares as treasury shares) in respect of any dividend the right to elect to receive Ordinary Shares by way of scrip dividend instead of cash. Any dividend unclaimed after a period of 12 years from the date when it was declared or became due for payment shall be forfeited and revert to the Company.

The Company may stop sending cheques, or similar financial instruments, in payment of dividends by post in respect of any shares or may cease to employ any other means of payment, including payment by means of a relevant system, for dividends if either (i) at least two consecutive payments have remained uncashed or are returned undelivered or that means of payment has failed or (ii) one payment remains uncashed or is returned undelivered or that means of payment has failed, and reasonable inquiries have failed to establish any new address or account of the holder. The Company may resume sending dividend cheques if the holder requests such resumption in writing.

Each Deferred Share confers an entitlement to a non-cumulative annual dividend at a fixed rate of 0.1 per cent. of its nominal value, payable on the first anniversary of their date of issue and on each such anniversary thereafter. The Deferred Shares carry no other right to participate in the profits or assets of the Company and carry no voting rights. The Deferred Shares may be redeemed in their entirety for an aggregate redemption payment of £1.

5.1.3 ***Transferability of Shares***

The shares are in registered form. Any shares in the Company may be held in uncertificated form and, subject to the Articles, title to uncertificated shares may be transferred by means of a relevant system. Provisions of the Articles do not apply to any uncertificated shares to the extent that such provisions are inconsistent with the holding of shares in uncertificated form or with the transfer of shares by means of a relevant system.

Subject to the Articles, any member may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any other form which the Board may approve. The instrument of transfer must be executed by or on behalf of the transferor and (in the case of a partly-paid share) the transferee.

The transferor of a share is deemed to remain the holder until the transferee's name is entered in the register.

The Board may, in its absolute discretion (but subject to any rules or regulations of the London Stock Exchange or any rules published by the UKLA applicable to the Company from time to time), decline to register any transfer of any share which is not a fully paid share. The Board may also decline to register a transfer of a certificated share unless the instrument of transfer:

(a) is duly stamped or certified or otherwise shown to the satisfaction of the Board to be exempt from stamp duty and is accompanied by the relevant share certificate and such other evidence of the right to transfer as the Board may reasonably require;

(b) is in respect of only one class of share; and

(c) if to joint transferees, is in favour of not more than four such transferees.

Registration of a transfer of an uncertificated share may be refused in the circumstances set out in the Regulations and where, in the case of a transfer to joint holders, the number of joint holders to whom the uncertificated share is to be transferred exceeds four.

The Board may decline to register a transfer of any of the Company's certificated shares by a person with a 0.25 per cent. interest if such a person has been served with a direction notice (as defined in the Articles) after failure to provide the Company with information concerning interests in those shares required to be provided under the Act, unless (i) the person is not himself in default as regards supplying the information requested, and (ii) the transfer is of part only of the member's holding and when presented for registration is accompanied by a certificate by the member in a form satisfactory to the Board to the effect that after due and careful enquiry the member is satisfied that no person in default as regards supplying such information is interested in any of the shares which are the subject of the transfer.

5.1.4 ***Variation of rights***

Subject to the Act, rights attached to any class of shares may be varied with the written consent of the holders of not less than three-fourths in nominal value of the issued shares of that class (calculated by excluding any shares held as treasury shares), or with the sanction of a special resolution passed at a separate general meeting of the holders of those shares. At every such separate general meeting (except an adjourned meeting) the quorum shall be two persons holding or representing by proxy not less than one-third in nominal value of the issued shares of the class (calculated by excluding any shares held as treasury shares).

The rights conferred upon the holders of any shares shall not, unless otherwise expressly provided in the rights attaching to those shares, be deemed to be varied by the creation or issue of further shares ranking *pari passu* with them.

5.1.5 ***Changes in capital***

The Company may by ordinary resolution increase, consolidate, consolidate and then divide, or (subject to the Act) sub-divide its shares or any of them. The Company may, subject to the Act, by special resolution reduce its share capital, share premium account, capital redemption reserve or any other undistributable reserve.

5.1.6 ***Untraced Shareholders***

The Company may sell any certificated shares in the Company on behalf of the holder of, or person entitled by transmission to, the shares at the best price reasonably obtainable at the time of sale if:

(a) the shares have been in issue throughout the period of 12 years immediately preceding the date of publication of the advertisements referred to in paragraph 5.13(iii) below or the first of the two advertisements to be published if they are published on different dates (the "Qualifying Period") and at least three cash dividends have become payable on the shares during that period and no cash dividend payable on the shares has either been claimed or satisfied in the manner specified in the Articles at any time during the period beginning on the commencement of the Qualifying Period and ending on the date when the requirements of paragraphs 5.13 (i) to (iii) have been satisfied (the "Relevant Period");

(b) the Company has not at any time during the Relevant Period received any communication from the holder of, or person entitled by transmission to, the shares; and

(c) the Company has published two advertisements, one in a newspaper with a national circulation and the other in a newspaper circulating in the area in which the last known postal address of the holder of, or person entitled by transmission to, the shares (or the postal address at which service of notices may be effected under the Articles) is located, giving notice of its intention to sell the shares and a period of three months has elapsed from the date of publication of the advertisements or of the last of the two advertisements to be published if they are published on different dates.

The net proceeds of sale shall belong to the Company and, upon their receipt, the Company shall become indebted to the former holder of, or person entitled by transmission to, the shares for an amount equal to the net proceeds.

5.1.7 ***Non-UK Shareholders***

There are no limitations in the Articles on the rights of non-UK shareholders to hold, or exercise voting rights attaching to, Ordinary Shares. However, no shareholder is entitled to receive notices from the Company (whether electronically or otherwise), including notices of general meetings, unless he has given a postal address in the UK or an address for the service of notices by electronic communication to the Company to which such notices may be sent.

5.1.8 ***General Meetings***

Subject to the provisions of the Act, an annual general meeting and a general meeting convened for the passing of a special resolution or a resolution of which special notice has been given to the Company shall be called by not less than twenty-one clear days' notice in writing. All other meetings shall be called by not less than fourteen clear days' notice in writing.

The notice must specify the place, day and time of the meeting and the general nature of the business transacted.

Notices shall be given to the auditors of the Company and to all members other than any who, under the provisions of the Articles or the terms of issue of the shares they hold, are not entitled to receive such notice. Notice may be via electronic communication and publication on a website in accordance with the Act.

Each director shall be entitled to attend and speak at any general meeting. The chairman of the meeting may invite any person to attend and speak at any general meeting where he considers that this will assist in the deliberations of the meeting.

The Board may direct that persons wishing to attend any general meeting should submit to such searches or other security arrangements or restrictions as the Board shall consider appropriate in the circumstances and shall be entitled in its absolute discretion to, or to authorise one or more persons who shall include a director or the secretary or the chairman of the meeting to refuse entry to, or to eject from, such general meeting any person who fails to submit to such searches or otherwise to comply with such security arrangements or restrictions.

5.1.9 ***Return of capital***

On a liquidation, the liquidator may, with the sanction of a special resolution of the Company and any other sanction required by the Act, divide among the members (excluding any member holding shares as treasury shares) in kind all or part of the assets of the Company (whether they shall consist of property of the same kind or not) and, for that purpose, set such values as the liquidator deems fair upon any property to be divided and determine how the division shall be carried out as between the members or different classes of members, or vest the whole or any part of the assets in trustees upon such trusts for the benefit of the contributories as the liquidator, with the like sanction, shall think fit, but no member shall be compelled to accept any shares or other assets upon which there is any liability.

5.1.10 ***Pre-emption rights***

There are no rights of pre-emption under the Articles in respect of transfers of issued Ordinary Shares.

In certain circumstances, the Company's shareholders may have statutory pre-emption rights under the Act in respect of the allotment of new shares in the Company. These statutory pre-emption rights would require the Company to offer new shares for allotment to existing shareholders on a *pro rata* basis before allotting them to other persons. In such circumstances, the procedure for the exercise of such statutory pre-emption rights would be set out in the documentation by which such shares would be offered to the Company's shareholders.

5.1.11 ***Sanctions on Shareholders***

Unless the Board otherwise determines, no Shareholder shall be entitled in respect of shares held by him to vote at a general meeting or meeting of the holders of any class of shares of the Company either personally or by proxy or to exercise any other right conferred by membership in relation to meetings of the Company or of the holders of any class of shares of the Company if any call or other sum presently payable by him to the Company in respect of such shares remains unpaid.

5.1.12 ***Directors' fees***

Each of the Directors shall be paid a fee at such rate as may from time to time be determined by the Board, but the aggregate of all such fees so paid to the Directors shall not exceed £200,000 per annum or such higher amount as may from time to time be decided by ordinary resolution of the Company. Any Director who is appointed to any executive office shall be entitled to receive such remuneration (whether by way of salary, commission, participation in profits or otherwise) as the Board or any committee authorised by the Board may decide, either in addition to or in lieu of his remuneration as a Director. In addition, any Director who performs services which in the opinion of the Board or any committee authorised by the Board go beyond the ordinary duties of a Director, may be paid such extra remuneration as the Board or any committee authorised by the Board may determine. Each Director may be paid his reasonable travelling, hotel and incidental expenses of attending and returning from meetings of the Board, or committees of the Board or of the Company or any other meeting which as a Director he is entitled to attend, and shall be paid all expenses properly and reasonably incurred by him in the conduct of the Company's business or in the discharge of his duties as a Director. The Company may also fund a Director's expenditure on defending proceedings (whether civil or criminal) as provided in the Act, or in connection with any application for relief from liability made by a Director under the Act.

5.1.13 ***Directors' conflicts of interest***

Subject to the provisions of the Act, and provided he has declared the nature of his interest to the Board as required by the Act, a Director is not disqualified by his office from contracting with the Company in any manner, nor is any contract in which he is interested liable to be avoided, and any Director who is so interested is not liable to account to the Company or the members for any benefit realised by the contract by reason of the director holding that office or of the fiduciary relationship thereby established.

A Director may hold any other office or place of profit with the Company in conjunction with his office of Director and may be paid such extra remuneration for so doing as the Board may decide, either in addition to or in lieu of any remuneration provided for by other Articles. A Director may also be or become a director or other officer of, or otherwise interested in, or contract with any company promoted by the Company or in which the Company may be interested and shall not be liable to account to the Company or the members for any benefit received by him, nor shall any such contract be liable to be avoided.

A Director may act by himself or his firm in a professional capacity for the Company (otherwise than as auditor) and he or his firm shall be entitled to remuneration for professional services.

5.1.14 ***Votes and Directors' interests***

No Director may vote on or be counted in the quorum in relation to any resolution of the Board concerning his own appointment, or the settlement or variation of the terms or the termination of his own appointment, as the holder of any office or place of profit with the Company or any other company in which the Company is interested save to the extent permitted specifically in the Articles. Except as mentioned below, no Director may vote on, or be counted in a quorum in relation to any resolution of the Board in respect of any contract in which he is to his knowledge materially interested and, if he does so, his vote shall not be counted. These prohibitions do not apply where that material interest arises only from one or more of the following matters:

(a) the resolution relates to the giving to him of a guarantee, security, or indemnity in respect of money lent to, or an obligation incurred by him for the benefit of the Company or any of its subsidiary undertakings;

(b) the resolution relates to the giving to a third party of a guarantee, security, or indemnity in respect of an obligation of the Company or any of its subsidiary undertakings for which the Director has assumed responsibility in whole or part and whether alone or jointly with others under a guarantee or indemnity or by the giving of security;

(c) the resolution relates to the giving to him of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other Directors and/or to the funding by the Company of his expenditure on defending proceedings or the doing by the Company of anything to enable him to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements;

(d) the resolution relates to the purchase or maintenance for any Director or Directors of insurance against any liability;

(e) his interest arises by virtue of his being, or intending to become, a participant in the underwriting or sub-underwriting of an offer of any shares in or debentures or other securities of the Company for subscription, purchase or exchange;

(f) the resolution relates to an arrangement for the benefit of the employees and Directors and/or former employees and former Directors of the Company or any of its subsidiary undertakings, and/or the members of their families (including a spouse or civil partner or a former spouse or former civil partner) or any person who is or was dependent on such persons, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any Director any privilege or advantage not generally accorded to the employees and/or former employees to whom the arrangement relates; or

(g) the resolution relates to a transaction or arrangement with any other company in which he is interested, directly or indirectly (whether as director or shareholder or otherwise) provided that he is not the holder of or beneficially interested in 1 per cent. or more of any class of the equity share capital of that company and not entitled to exercise 1 per cent. or more of the voting rights available to members of the relevant company (and for the purpose of calculating the said percentage there shall be disregarded (i) any shares held by the Director as a bare or custodian trustee and in which he has no beneficial interest, (ii) any shares comprised in any authorised unit trust scheme in which the Director is interested only as a unit holder, and (iii) any shares of that class held as treasury shares).

Subject to the Act, the Company may by ordinary resolution suspend or relax the above provisions to any extent or ratify any transaction not duly authorised by reason of a contravention of such provisions.

5.1.15 ***Retirement***

At every annual general meeting, there shall retire from office any Director who shall have been a Director at each of the two preceding annual general meetings and who was not appointed or re-elected by the Company in a general meeting at, or since, either such annual general meeting. A retiring Director shall be eligible for re-election. A Director retiring at a meeting shall, if he is not re-elected at such meeting, retain office until the conclusion of the meeting or adjourned meeting at which he is due to retire. Where a Director is a non-executive director and has been in office for nine years or more he shall retire from office at every annual general meeting.

Subject to the provisions of the Articles, at the meeting at which a Director retires the Company can pass an ordinary resolution to re-elect the Director or to elect some other eligible person in his place.

5.1.16 ***Borrowing powers***

Subject to the Articles and the Act, the business of the Company will be managed by the Board who may exercise all the powers of the Company, whether relating to the management of the business of the Company or not. In particular, the Board may exercise all the powers of the Company to borrow money and to mortgage or charge any of its undertaking, property, assets (present and future) and uncalled capital and to issue debentures and other securities and to give security for any debt, liability or obligation of the Company or of any third party. The Board must restrict the borrowings of the Company and exercise all voting and other rights or powers of control exercisable by the Company in relation to its subsidiary undertakings so as to secure that the aggregate principal amount from time to time outstanding of all borrowings by the group (exclusive of borrowings within the group) shall not, without the previous sanction of an ordinary resolution of the Company, exceed £10 million.

5.1.17 ***Objects***

The Articles do not provide for any objects of the Company and accordingly, the Company's objects are unrestricted.

6. INTERESTS OF THE MANAGEMENT

6.1 The interests (all of which are beneficial unless otherwise stated) of the Directors and the Finance Manager and their immediate families and the persons connected with them (within the meaning of section 252 of the Act) in the Existing Share Capital or the existence of which could, with reasonable diligence, be ascertained by any Director or the Finance Manager as at the date of this Document and as expected to be immediately following Admission are as follows:

	At the date of this Document and on Admission				
Name	*No. of Ordinary Shares*	*% of Existing Share Capital*	*No. of Ordinary Shares over which Warrants are granted*	*No. of Ordinary Shares over which Options are granted*	*% of fully diluted Ordinary share capital*
Brian Larkin	9,755,691	2.82%	9,755,690	4,235,294	5.41%
Jonathan Leather	4,877,810	1.41%	4,877,810	4,058,824	3.15%
Graham Martin	1,411,764	0.41%	0	1,176,471	0.59%
Alberto Cattaruzza	0	0.00%	0	352,941	0.08%
Rodney Mooney	0	0.00%	0	1,294,118	0.29%
Total	16,045,265	4.64%	14,633,500	11,117,648	9.52%

6.2 Other than the abovementioned Ordinary Shares, Warrants and Options, no Director or any person connected with any said Director holds any interest in Ordinary Shares or any related financial product related to Ordinary Shares.

6.3 Save as disclosed above, none of the Directors (or persons connected with the Directors within the meaning of section 252 of the Act) has any interest, whether beneficial or non-beneficial, in any share or loan capital of the Company.

6.4 There are no outstanding loans granted or guarantees provided by the Company to or for the benefit of any of the Directors.

6.5 Save as disclosed above, and save as otherwise disclosed in this Document, no Director has any interest, whether direct or indirect, in any transaction which is or was unusual in its nature or conditions or significant to the business of the Company taken as a whole and which was effected by the Company since its incorporation and which remains in any respect outstanding or under-performed.

6.6 None of the Directors or any person connected with them (within the meaning of section 252 of the Act) is interested in any related financial product referenced to the Ordinary Shares (being a financial product whose value is, in whole or in part, determined directly or indirectly by reference to the price of the Ordinary Shares including a contract for difference or a fixed odds bet).

7. DIRECTORS' AND FINANCE MANAGER'S TERMS OF ENGAGEMENT

7.1 *Executive Directors*

7.1.1 Brian Larkin was appointed by the Company to act as Chief Executive Officer under a service agreement dated 25 July 2017. His appointment commenced on 31 July 2017 and continues unless terminated on not less than six months' prior written notice on either side with such notice not to be given prior to the first anniversary. He is entitled to a fee of £120,000 per annum.

7.1.2 Jonathan Leather was appointed by the Company to act as Technical Director under a service agreement dated 25 July 2017. His appointment commenced on 31 July 2017 and continues unless terminated on not less than six months' prior written notice on either side with such notice not to be given prior to the first anniversary. He is entitled to a fee of £115,000 per annum. Mr Leather's current role is Chief Operating Officer. A new service agreement has not been entered into as a result of this change of role.

7.2 *Non-Executive Directors*

7.2.1 Graham Martin was appointed by the Company to act as Non-Executive Chairman under a letter of appointment dated 15 February 2018. His appointment commenced on 19 February 2018, is for an initial term of three years and is terminable on one month's prior written notice by either party. He is entitled to a fee of £40,000 per annum.

7.2.2 Alberto Cattaruzza was appointed as a director of the Company on 4 November 2015 and his appointed as a Non Executive Director is regulated by a letter of appointment dated 25 July 2017. His appointment is terminable on three months' prior written notice by either party. He is entitled to a fee of £15,000 per annum.

7.3 *Finance Manager*

7.3.1 Rodney Mooney was appointed by the Company to act as Finance Manager under a service agreement dated 23 October 2017. His appointment commenced on 23 October 2017 and continues unless terminated by either party giving the other not less than two months' notice in writing. He is entitled to a fee of EUR 60,000 per annum.

7.4 The aggregate remuneration and benefits in kind, paid by the Company to the Directors by any member of the Group in respect of the financial year ending 31 December 2017 (being the last completed financial year of the Group) was £191,792.

8. ADDITIONAL INFORMATION ON THE DIRECTORS

8.1 Other than the directorship of the Company, the names of all companies and partnerships of which the Directors have been a director or partner at any time in the five years preceding the date of this Document and indicating whether they are current or past are set out below:

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
Graham Martin	Kenmare Resources plc Sabelgrade Limited Meadowside Twickenham Limited	Energy Africa UK Limited Planet Oil International Limited Planet Oil Limited Tullow CMS (North Sea) Limited Tullow Energy Limited Tullow Exploration and Production UK Limited Tullow Greenland Exploration Limited Tullow Group Services Limited Tullow Guinea Limited Tullow Jamaica Limited Tullow Oil (International) Norge Limited Tullow Oil Finance Limited Tullow Oil plc Tullow Oil SK Limited Tullow Oil SNS Limited Tullow Oil SPE Limited Tullow Oil 100 Limited Tullow Oil 101 Limited Tullow Oil TS Limited Tullow Mozambique Limited Tullow Uruguay Limited Tullow Gambia Limited Tullow Côte D'Ivoire Onshore Limited Tullow Africa New Ventures Limited Tullow Chinguetti Production Pty Ltd Hardman Mauritania Finance Pty Ltd Hardman Oil and Gas Pty Ltd Tullow Petroleum (Mauritania) Pty Ltd Hardman Petroleum (Uganda) Pty Ltd Hardman Petroleum (West Africa) Pty Ltd Hardman Petroleum Tanzania Pty Ltd Hardman Resources Pty Ltd Tullow Uganda Operations Pty Ltd Tullow Cote D'Ivoire Exploration Limited Tullow Cote D'Ivoire Limited Tullow Madagascar Limited Tullow Ghana Limited Tullow India Operations Limited Tullow Oil International Limited Tullow Pakistan (Developments) Limited Tullow Oil Limited Tullow Oil Overseas Finance Limited Tullow South Africa (Pty) Limited EA Bredasdorp Pty Ltd Tullow Oil Gabon SA Tulipe Oil SA

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
Graham Martin (continued)		Invest in Africa Tullow Oil Holdings (Guernsey) Ltd Tullow Oil (Mauritania) Ltd Eagle Drill Limited Tullow (EA) Holdings Limited Tullow Oil Norge AS Tullow Oil (Bream) Norge AS Hardman Petroleum France SAS T.U. S.A. Tullow Do Brasil Petroleo E Gas Ltd Tullow Oil Canada Ltd Tullow Uganda Limited Tullow Congo Limited Tullow Senegal Limited Tullow Mauritania Limited Tullow Kudu Limited Tullow Gabon Limited Tullow Gabon Holdings Limited Tullow Equatorial Guinea Limited Tullow Mexico BV Tullow Angola BV Tullow DRC BV Tullow Ethiopia BV Tullow Sierra Leone BV Tullow Guyana BV Tullow Tanzania BV Tullow Kenya BV Tullow Liberia BV Tullow Zambia BV Tullow 101 Netherlands BV Tullow 6 BV Tullow Exploration & Production BV Tullow Exploration & Production Netherlands BV Tullow Global Compliance BV Tullow Hardman Holdings BV Tullow Netherlands Holding Cooperatief BA Tullow Overseas Holdings BV Tullow Suriname BV Tullow Uganda Holdings BV Zetah Kouilou Limited Tullow Bangladesh Limited Energy Africa Namibia Limited Tullow Romania Limited Tullow Senegal Operations Limited Tullow Filala Romania S R L Tullow Trinidad Limited General Mining Union Corp (UK) Ltd Unitrust Holdings Limited Jubilee Support Services INC Tullow Netherlands BV

Director	*Current directorships/partnerships*	*Past directorships/partnerships*
Brian Larkin	UOG Holdings Plc UOG Ireland Limited UOG PL090 Limited UOG Italia S.r.l UOG Jamaica Limited UOG Colter Limited UOG Crown Limited	BLUOG Limited
Jonathan Leather	UOG Holdings Plc UOG Ireland Limited UOG PL090 Limited UOG Italia S.r.l UOG Jamaica Limited UOG Colter Limited UOG Crown Limited	None
Alberto Cattaruzza	None	None

8.2 None of the Directors has:

8.2.1 any unspent convictions in relation to indictable offences;

8.2.2 had any bankruptcy order made against him or entered into any voluntary arrangements;

8.2.3 been a director of a company which has been placed in receivership, compulsory liquidation, administration, been subject to a voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors whilst he was a director of that company or within the 12 months after he ceased to be a director;

8.2.4 been a partner in any partnership which has been placed in compulsory liquidation, administration or been the subject of a partnership voluntary arrangement whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

8.2.5 been the owner of any asset or been a partner in any partnership which owned any asset which while he owned that asset, or while he was a partner or within the 12 months after he ceased to be a partner in the partnership which owned the asset, entered into receivership;

8.2.6 been the subject of any public criticism by any statutory or regulatory authority (including recognised professional bodies); or

8.2.7 been disqualified by a court from acting as a director of any company or from acting in the management or conduct of the affairs of any company.

8.3 Save as disclosed in this Document, none of the Directors has or has had any interest in transactions effected by the Company since its incorporation which are or were unusual in their nature or conditions or which are or were significant to the business of the Company.

8.4 Each of the Directors and the Finance Manager has given an undertaking not to dispose of any of their Ordinary Shares (if any), save in certain specified circumstances, for the period of 12 months from the date of Admission and for six months following such period, they will only dispose of their Ordinary Shares through the Company's broker in order to create an orderly market.

8.5 No loans made or guarantees granted or provided by the Company or any Group company to or for the benefit of any Director are outstanding.

9. SIGNIFICANT SHAREHOLDERS

9.1 Save as disclosed in paragraph 6.1 of this Part VII, the Company is only aware of the following persons who, at the date of this Document and immediately following Admission, represent an interest (within the meaning of Disclosure and Transparency Rules, Chapter 5) directly or indirectly, jointly or severally, in three per cent. or more of the Existing Share Capital or could exercise control over the Company:

	At the date of this Document and on Admission	
Name	*No. of Ordinary Shares*	*% of Existing Share Capital*
JIM NOMINEES LIMITED (JARVIS)	118,383,599	34.25%
HARGREAVES LANSDOWN (NOMINEES) LIMITED (VRA)	21,200,898	6.13%
HARGREAVES LANSDOWN (NOMINEES) LIMITED (15942)	16,027,226	4.64%
SECURITIES SERVICES NOMINEES LIMITED (1009009)	15,789,462	4.57%
INTERACTIVE INVESTOR SERVICES NOMINEES LIMITED (SMKTISAS)	11,891,150	3.44%
HARGREAVES LANSDOWN (NOMINEES) LIMITED (HLNOM)	11,133,370	3.22%

9.2 None of the Directors, the Finance Manager nor any persons named in paragraph 9.1 has voting rights which are different to any other holder of Ordinary Shares.

9.3 Save as disclosed in paragraph 9.1 above, the Company and the Directors are not aware of (i) any person or entity who directly or indirectly, jointly or severally, exercises or could exercise control over the Company at Admission, nor (ii) any arrangements the operation of which may at a subsequent date result in a Change of Control of the Company at Admission.

10. EMPLOYEES

10.1 As at the date of this Document the Company has three full time employees. The number of employees employed in the Group (by reference to the year-end of 31 December) for each of the last two financial years was as follows: one (2017) and two (2018).

10.2 The breakdown of persons employed by main category of activity was as follows:
1 Finance, 1 Technical Services and 1 Administrative Support.

11. MATERIAL CONTRACTS

The following contracts: (i) (not being contracts entered into in the ordinary course of business) have been entered into in the two years preceding the date of this document by any member of the Group and are, or may be, material to the Group or have been entered into by any member of the Group and contain any provision under which any member of the Group has any obligation or entitlement which is material to the Group at the date of this document; or (ii) are subsisting agreements which are included within or which relate to the oil assets and liabilities of the Group (notwithstanding whether such agreements are within the ordinary course or were entered into outside of the 2 years immediately preceding the publication of this document) and are, or may be material to the Group:

11.1 ***Engagement Letter between Beaumont Cornish and the Company***

An engagement letter dated 16 October 2018 was signed by the Company under which Beaumont Cornish agreed to act as the Company's financial adviser in connection with the Admission and the Company's nominated adviser for purposes of the AIM Rules. In consideration of the services set out in the engagement letter, the Company agreed to pay Beaumont Cornish a fee of £65,000 plus applicable VAT and disbursements.

11.2 ***Nominated Adviser Agreement between Beaumont Cornish and the Company***

The Company and Beaumont Cornish entered into a nominated adviser agreement dated 22 February 2019 pursuant to which Beaumont Cornish agreed to act as the nominated adviser to the Company for the purposes of the AIM Rules. The agreement is for an initial term of 12 months conditional on

Admission and may be terminated by either party by giving the other party 3 months written notice provided if such notice is given by the Company, it does not expire earlier than the first 12 months. The Company has agreed to pay Beaumont Cornish an annual fee of £50,000 plus VAT in accordance with terms of the agreement.

11.3 ***Introduction Agreement between Beaumont Cornish and the Company***

An introduction agreement dated 22 February 2019 was entered into by the Company, the Directors and Beaumont Cornish in respect of the Admission and the obligations and responsibilities of the parties. The Company has agreed to pay Beaumont Cornish a fee of £65,000.

The Introduction Agreement contains indemnities from the Company and warranties from the Company and the Directors in favour of Beaumont Cornish. The liability of the Directors for breach of warranty is limited.

In addition, it has been agreed to appoint another independent non-executive director with appropriate financial expertise within 6 months of the date of the Admission and to appoint a finance director at the appropriate juncture.

11.4 ***Broker Engagement Letter***

The Company and Optiva entered into an engagement letter dated 22 February 2019 with respect to the appointment by the Company of Optiva as broker for the purposes of the AIM Rules. In consideration of the services to be provided by Optiva, the Company has agreed to pay an annual retainer of £25,000 conditional on Admission. In addition, Optiva will be entitled to the following:

- 5 per cent. placing commission fee of the funds raised and/or introduced by Optiva in any fundraising by the Company;
- 5 per cent. broker warrants in the Company exercisable at the placing price of each placing and exercisable for a period of 3 years from the date of completion of such placings equal in value to the placing commission fee above; and
- 1 per cent. handling fee in respect of funds not raised by Optiva where they send out placing letters and/or subscription agreements on behalf of the Company.

The appointment may be terminated by either party on giving not less than 3 months' prior written notice provided such notice does not expire earlier than 12 months from Admission.

11.5 ***Waddock Cross Field Sale and Purchase Agreement***

On 14 June 2016, First Oil Expro Limited (In Administration) acting by its agents, the Administrators (as defined in this paragraph) Richard James Beard and James Robert Tucker of KPMG LLP, and Blair Carnegie Nimmo of KPMG LLP (together the "Administrators") and UOG PL090 (a wholly owned subsidiary of UOG UK), entered into an agreement for the sale by FOEL and purchase by UOGPL090 of such rights, title and interest (if any) FOEL had in certain petroleum production licences (the "Purchase").

The Purchase comprised of an initial deposit of USD$ 10,000 payable to FOEL on execution of the sale and purchase agreement held in an escrow account, and the remaining consideration of USD$ 115,000 payable by UOG PL090 to FOEL, as adjusted pursuant to Schedule 2 of the sale and purchase agreement (the "Final Consideration"), for FOEL's:

(a) undivided legal and beneficial interest in United Kingdom Petroleum Production Licence No. PL090 dated 30 May 1968 and United Kingdom Licence No. PEDL237 dated 30 October 2008 (together, the "Licences");

(b) entire interest in and under the joint operating agreements in respect of the Licences (the "JOAs");

(c) entire interest in the petroleum production, wellhead, platform, processing and transportation facilities, equipment or other materials and the interconnecting pipelines used in relation to the hydrocarbon accumulation known as Waddock Cross field; and

(d) the entire legal and beneficial, right, title and interest in all data in the possession of FOEL relating to the above mentioned interests and forming part of the property jointly owned by FOEL and other parties to the JOAs.

The Final Consideration payable on completion of the Sale and Purchase Agreement resulted in the total consideration being paid by UOG PL090 to FOEL of the sum of USD$ 126,913.

11.6 ***Waddock Cross Field Sale and Purchase Agreement Side Letter***

On 14 June 2016, FOEL, the Administrators and UOG PL090 entered into a side letter to the Waddock Cross Field Sale and Purchase Agreement (the "Side Letter"). In connection with a joint venture waiver letter dated 2 June 2016 from Aurora Production (UK) Limited, Dorset Exploration Limited, Egdon Resources U.K. Limited and Egdon Resources plc addressed to FOEL, in relation to an understanding between the parties under the JOAs (the "JV Waiver Letter"), it was agreed that at completion, that in relation to the aggregate amounts outstanding under the terms of the JOAs (being approximately £68,408.50 as the date of the JV Waiver Letter) owing from FOEL:

(a) FOEL pays £55,085.95 to Egdon (as operator pursuant to the JOAs), being an amount equal to the outstanding sums due by FOEL under the JOAs in respect of the periods prior to 00:01 hours (London time) on 1 January 2016 (the "Economic Date");

(b) FOEL pays £6,301.28 to Egdon (as operator pursuant to the JOAs), being an amount equal to half of the outstanding sums due by FOEL under the JOAs in respect of the period from the Economic Date to the date of the JV Waiver Letter;

(c) UOG PL090 pays £6,301.28 to Egdon (as operator pursuant to the JOAs), being an amount equal to half of the outstanding sums due by FOEL under the JOAs in respect of the period from the Economic Date to the date of the JV Waiver Letter; and

(d) UOG PL090 pays to Egdon (as operator pursuant to the JOAs), an amount equal to the outstanding sums due by FOEL under the JOAs in respect of the period from the date of the JV Waiver Letter to completion.

On completion, UOG PL090 paid a total of £13,035.79 to Egdon.

11.7 ***Deed of Assignment of PL090***

On 11 August 2016, FOEL, the Administrators, Aurora, Corfe Energy Limited, Dorset and Egdon assigned to Aurora, Corfe, Dorset, Egdon, and UOG PL090, all rights, interest, obligations and liabilities of PL090, with the consent of The Secretary of State for Energy and Climate Change.

11.8 ***Deed of Novation of Agency Agreement relating to PL090***

On 11 August 2016, FOEL, the Administrators, UOG PL090, and Aurora, Corfe, Dorset, Egdon and Star Energy Weald Basin Limited, executed a deed of novation, whereby FOEL ceased to be a party to an Oil Handling Promotion and Sales Agency Agreement relating to Crude Oil produced from the Oil Field at Licence Area PL090 dated 11 October 2013 (the "Affected Agreement"), and FOEL transferred its entire undivided legal and beneficial interest in and under the Affected Agreement, together with all rights, title, obligations, liabilities and interests attaching thereto, to UOG PL090, in relation to a 26.25 per cent. interest in PL090.

11.9 ***Deed of Novation of Affected Petroleum Agreements***

On 11 August 2016, FOEL, the Administrators, UOG PL090, and Aurora, Corfe, Dorset and Egdon executed a deed of novation whereby FOEL ceased to be a party to certain affected petroleum agreements (the "Affected Petroleum Agreements") in respect of FOEL's:

(a) 26.25 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PL090 dated 3 February 1997 as applied to a separate contract to Area A (Waddock Cross) (the "Area A JOA");

(b) 22.6042 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PL090 dated 3 February 1997 as applied as a separate contract to Area B (the "Area B JOA"); and a

(c) 22.6042 per cent. legal and beneficial title and interest in, and rights, obligations and liabilities under the Joint Operating Agreement in respect of PEDL237 dated 26 March 2013 (the "PEDL 237 JOA"),

(together, the "Operating Agreements") together with all corresponding legal and beneficial rights, title, interest and obligations under the Affected Petroleum Agreements.

The recital to this deed records that PEDL237 expired as of 30 June 2016, however as the PEDL 237 JOA had not been terminated, it was being novated pursuant to this deed.

This deed records that the pre-transfer, and following execution of this deed, the post-transfer per cent. interests of the participants held under the Operating Agreements are as follows:

(a) The Area A JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	18.750%	18.750%
Dorset	10.000%	10.000%
Egdon	45.000%	45.000%
FOEL	26.250%	0.000%
UOG PL090	0.000%	26.250%
Total	100%	100%

(b) The Area B JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	16.1458%	16.1458%
Corfe	12.500%	12.500%
Dorset	10.000%	10.000%
Egdon	38.750%	38.750%
FOEL	22.6042%	0.000%
UOG PL090	0.000%	22.6042%
Total	100%	100%

(c) The PEDL 237 JOA

Participant	*Pre-transfer (%)*	*Post-transfer (%)*
Aurora	16.1458%	16.1458%
Corfe	12.500%	12.500%
Dorset	10.000%	10.000%
Egdon	38.750%	38.750%
FOEL	22.6042%	0.000%
UOG PL090	0.000%	22.6042%
Total	100%	100%

11.10 ***Podere Gallina Farm-in Agreement***

On 4 May 2017, UOG UK and Po Valley Operations Pty Ltd, a company incorporated and registered in Australia, a wholly owned subsidiary of Po Valley Energy Ltd, entered into the Podere Gallina Farm-in Agreement, pursuant to which PVO conditionally agreed to sell to UOG UK, and UOG UK conditionally agreed to acquire from PVO, a 20 per cent. interest in the Podere Gallina Exploration Licence ("Participating Interest") held by PVO and awarded by the Ministry of Economic Development (the "Ministry") on 2 December 2008 (the "Exploration Licence"), and which includes the Podere Maiar-1 exploration well (the "Exploration Well").

On execution of this agreement, UOG UK paid to PVO an exclusivity fee of €50,000 (the "Exclusivity Fee") for the period commencing 19 April 2017 and ending at 12 p.m. on 31 July 2017 (or such other later time and date as agreed by the parties in writing) (the "Exclusivity Period"). The Exclusivity Fee would only be refunded to UOG UK in the event PVO withdraws from negotiations.

Additionally, on execution of this agreement, UOG UK agreed to file an application with the Ministry to qualify as a non-operating entity. Immediately after UOG UK has received confirmation from the Ministry that its application has been approved, PVO agreed to file with the Ministry an application to obtain preliminary authorisation to assign to UOG UK the Participating Interest ("Preliminary Approval").

Subject to UOG UK raising a minimum of £3 million by the end of the Exclusivity Period, either by way of:

(a) new or existing shareholders subscribing for shares;

(b) completion of admission of UOG UK's shares to trading on the Standard segment of the Main Market of the London Stock Exchange and a concurrent fundraising associated therewith; and/or

(c) any other fundraising methods that UOG UK may in its absolute discretion may choose (each a "Fundraising Event"),

PVO agreed to sell and UOG UK agreed to purchase the Participating Interest.

In consideration of the purchase of the Participating Interest, UOG UK agreed to pay to PVO the sum of €1,280,000. It was agreed that the consideration be applied towards costs associated with the Exploration Well, as set out in a Budget attached to the agreement ("Well Costs"). The promote element, that is incremental 20 per cent. of the Well Costs paid by UOG UK in addition to their *pro rata* share of the Participating Interest, is capped at €640,000.

Any additional costs incurred on the Exploration Licence above the Well Costs would be allocated proportionately between UOG UK and PVO on a 20/80 split, in accordance with their respective participating interests.

Under the agreement, upon the later of the date of completion of a Fundraising Event, or the date falling 15 days after the granting of the Preliminary Approval, UOG UK and PVO were to execute:

(a) a deed of transfer of the Participating Interest in front of a Notary Public in Rome; and

(b) a joint operating agreement governing the working relationship between the parties.

11.11 *Deed of Collective Novation*

On 14 June 2017, Egdon, Aurora, UOG PL090, Corfe and Dorset executed a deed of collective novation in respect of a joint operating agreement and a trust deed relating to PL090 Area A (Waddock Cross) and Area B (Other) and other agreements. The recital to the deed records that Egdon, Aurora and UOG PL090 wished to be released and discharged from their liabilities in respect of the Area B JOA and provided opt-out notices to Corfe (the "Opt-Out Notices"). Egdon assigned to Corfe 6.2500 per cent., Aurora assigned to Corfe 2.6041 per cent., and UOG PL090 assigned to Corfe 3.6459 per cent. (the "Opt-Out Interests"). The effect of the Opt-Out Notices on the Area B JOA was that the percentage interests of the parties were varied as set out below. These variations also applied to the other related agreements where the table appears:

Participant	*Pre-Opt-Out Notice (%)*	*Post-Opt-Out Notice (%)*
Aurora	16.1458%	13.5417%
Corfe	12.5000%	25.0000%
Dorset	10.0000%	10.0000%
Egdon	38.7500%	32.5000%
UOG PL090	22.6042%	18.9583%
Total	100%	100%

11.12 ***Supplement to Earn-in Agreement***

On 14 June 2017, Egdon, Aurora, UOG PL090 and Corfe executed a supplement to an earn-in agreement dated 23 March 2013 (the “Earn-in Agreement”) in relation to United Kingdom onshore licences PL090 and PEDL237. The Earn-in Agreement was novated under the Deed of Novation of Affected Petroleum Agreements set out at paragraph 20.1.5. The parties entered into the agreement to clarify or modify the application of certain provisions in the Earn-in Agreement relating to the exercise of the Opt-Out Notices.

The agreement provides that subject to the Earn-in Agreement, Egdon, Aurora and UOG PL090 shall cease to be required to pay earn-in costs under the Area B JOA after the accounting date. The agreement notes that Egdon, as operator under the Area B JOA, had agreed with the EPI Group a contract for certain seismic processing services. The contract included the below schedule of services and prices:

Item		*Unit*	*Rate*
1	Seismic Processing – test sequence as defined in EPI’s “Proposal for Seismic Processing Services” to CLIENT dated 13 December 2016	Lump Sum	£10,800
2	Full delivery of pre & post stack data	Lump Sum	£32,400
3	Full depth imaging sequence	Lump Sum	£39,350
4	PSDM ‘lite’ depth imaging	Lump Sum	£9,800

Under the agreement, the cost of Item 1 is an item for which Egdon, Aurora and UOG PL090 are bound to pay for the shares attributable to their respective Opt-Out Interests as it was contracted before the accounting date. Provided that the decision to proceed with the contract with the EPI Group in respect of Items 2, 3 and 4 is taken after the accounting date, the then the costs associated with Items 2, 3 and 4 will only accrue on or after the date the decision is taken, and accordingly the share of the costs attributable to the Opt-Out Interests will be payable by Corfe.

11.13 ***Acquisition Agreement***

The Company agreed on 25 July 2017 to purchase the entire issued share capital of UOG UK from the Vendors subject to certain conditions. The consideration for the Acquisition comprised of new Ordinary Shares (representing 26.84 per cent. of the share capital of the Group as at 31 July 2017).

The Vendors provided certain warranties in respect of their ownership of the shares of UOG UK in the Acquisition Agreement. Brian Larkin as warrantor provided certain warranties in the Acquisition Agreement. The warranties relate, *inter alia*, to accounting and financial matters, regulatory and legal matters, intellectual property matters, taxation, litigation, assets and employees.

Brian Larkin’s liability under the Acquisition Agreement was limited to the purchase price.

11.14 ***2017 Placing Agreement***

On 25 July 2017, (1) Beaumont Cornish; (2) Optiva; (3) the Company; (4) the Former Directors; and (5) the Directors entered into a placing agreement.

Under this agreement, Beaumont Cornish agreed to act as financial adviser to the Company and Optiva agreed to use its reasonable endeavours (as agents of the Company) to procure subscribers for Ordinary Shares at a placing price of 2.5 pence per Ordinary Share.

In consideration for the services provided by Beaumont Cornish and Optiva, the Company agreed:

(a) to pay Beaumont Cornish:

  (i) a corporate finance fee of £50,000; and

  (ii) to issue the Beaumont Cornish Warrants to Beaumont Cornish pursuant to the Beaumont Cornish Warrant Instrument; and

(b) to pay Optiva:

  (i) a corporate finance fee of £15,000;

(ii) pay Optiva a commission of 5 per cent. of the aggregate value of the Ordinary Shares at a placing price of 2.5 pence per Ordinary Share where such placees had been introduced by Optiva; and

(iii) to issue the Optiva Warrants to Optiva pursuant to the Optiva Warrant Instrument.

The Company, the Former Directors and the Directors gave certain warranties in relation to the Company and the business of the Group. The Company, the Former Directors and the Directors gave certain customary warranties and indemnities to Beaumont Cornish and Optiva.

11.15 ***Beaumont Cornish Warrant Instrument***

Pursuant to the Beaumont Cornish Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 3,200,000 Beaumont Cornish Warrants which each entitle Beaumont Cornish to subscribe for 1 new Ordinary Share at 2.5p per Ordinary Share for a period of five years from 31 July 2017. The Beaumont Cornish Warrants are unlisted, fully transferable and are exercisable in whole or in part.

11.16 ***Optiva Warrant Instrument***

Pursuant to the Optiva Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 6,000,000 Optiva Warrants which each entitle Optiva to subscribe for 1 new Ordinary Share at 2.5p per share for a period of three years from 31 July 2017. The Optiva Warrants are unlisted, fully transferable and are exercisable in whole or in part.

11.17 ***UOG Warrant Instrument***

Pursuant to the UOG Warrant Instrument dated 25 July 2017 and executed by the Company, the Company issued 28,000,000 UOG Warrants which each entitle the holder of such warrants to subscribe for 1 new Ordinary Share at the exercise price of 1.42857 pence for a period of five years from 31 July 2017. The UOG Warrants are unlisted, freely transferable after on 31 July 2018, and are exercisable in whole or in part. The exercise price of 1.42857 pence was calculated based on the agreed acquisition ratio for the shares of UOG UK.

11.18 ***Italian JOA***

On 18 October 2017 and further to the Podere Gallina Farm-in Agreement detailed at paragraph 11.10 above, PVO and UOG Italy entered into a joint operating agreement (the "Italian JOA") in respect of the Podere Gallina exploration licence. PVO is the operator of the petroleum activity operations and activities forming the subject of this agreement.

The agreement is based on the Model JOA for joint ventures in Italy and contains the normal clauses and financial and operations procedures common to Italian agreements of this type.

The Italian JOA became effective on 31 July 2017 and recorded the participating interests of the parties as PVO holding 80 per cent. and UOG Italy holding 20 per cent. Within 90 days of the signature of this agreement, the parties were to set up an operating committee comprised of the parties' representatives, the chairman of which is the representative of PVO. The operating committee is qualified to decide upon work programs and budgets as well as upon any matters regarding the orderly supervision and director of the petroleum activity and is convened at least once a year by the operator to approve the work program and relevant budget.

Decisions of the operating committee are passed by at least two parties not being affiliates, representing at least 50 per cent. of the aggregate participating interests. Certain decisions require the unanimous vote of the representatives such as: (a) the voluntary relinquishment or expiry without request of a mining licence or a portion of the area of a mining licence; (b) the enlargement of the area of a mining licence; (c) the decision to authorise the operator in respect of an approved annual work program to make budget item expenditures in excess of the relevant budget exceeding ten per cent. of each item of such budget (which will not be unreasonably withheld); and (d) the decision to authorise the operator in respect of the aggregate of the excess budget expenditures to exceed five per cent. of the total approved budget (also not to be unreasonably withheld).

Also within 90 days of the signature of this agreement, the parties were to set up a technical committee to assist and advise the operating committee, which is comprised of representatives of each party. The chairman on this committee is the representative of PVO. The functions of the technical committee include: (a) to keep the parties regularly informed of the execution of operations in the contract area; (b) to cooperate in the preparation of work programs; and (c) to prepare appropriate recommendations for the operating committee.

The functions of the operator are in accordance with and subject to the work programs and relevant budgets approved by the operating committee. In carrying out its duties, the operator has various duties such as: (a) using its best efforts to ensure that all operations are conducted as diligently, economically, safely, efficaciously and efficiently as possible in accordance with good international petroleum industry practices and engineering techniques, and in compliance with applicable laws and regulations; (b) to supply promptly to the parties various documentation (such as surveys and statistics); (c) prepare and supply various reports and data; and (d) pay on behalf of the parties the indirect taxes and any other amounts due under the mining licences.

The operator undertook to carry out the work programs approved by the operating committee and agreed not to undertake any operations not included in said approved programs. The operator is authorised to make expenditures with regard to each annual work program and relevant approved budget, to make expenditures for operations in the contract area not contemplated in the work program and budget for a total amount not exceeding EUR 51,645.69.

The agreement sets out the procedures for awarding contracts that either exceed, or do not exceed, EUR 250,000.

The operator has the right to resign from its duties at any time by giving the non-operators no less than three months' prior written notification. In the event the operator holds a participating interest of less than 50 per cent. by way of assignment, the operator is to notify the non-operators of its willingness to resign provided that one of the parties is prepared to take over the duties as operator and that party's participating interest is at least twice as much as the participating interest the operator would be left with after the assignment.

The agreement contains a procedure to remove the operator if the non-operators deem the operator responsible for gross negligence, wilful misconduct or fraud during the performance of its duties.

Within 120 days of notification of resignation of the operator, the parties will appoint one of them as the new operator, subject to the relevant provisions concerning that party's participating interest.

All costs and expenses relating to the petroleum activity are borne by the parties in proportion to their respective participating interests and in accordance with the accounting procedure. Any costs or expenses relating to the petroleum activity resulting from actions or omissions committed by the operator with gross negligence, wilful misconduct or fraud are borne entirely by the operator. In the event a party fails to pay its proportion, interest is payable and the non-defaulting parties will be invited to pay the additional shares of the funds required, in proportion to the ratio of their participating interest to the aggregate of the non-defaulting parties. Each party will also pay its share of the succeeding calls for funds, in the proportions detailed above. These payments will continue until the defaulting party has remedied its default, or the defaulting party's participating interest has been taken over or the agreement has been terminated as the non-defaulting parties decide not to take over the defaulting party's participating interest. In the event of default, the defaulting party loses various entitlements under the agreement, including voting and participating rights at meetings.

Each party owns, in proportion to its respective participating interest, all petroleum discovered and produced in the contract area, subject to the relevant articles of the agreement and unless otherwise agreed by the parties in writing.

The Italian JOA is governed by Italian law.

11.19 ***Tullow Jamaica Farm-out Agreement***

On 24 November 2017, Tullow Jamaica and UOG Jamaica entered into a farmout agreement pursuant to which Tullow Jamaica agreed to transfer an undivided legal and beneficial twenty per cent. interest in the production sharing agreement between Tullow Jamaica and the PCJ dated 16 October 2014 (with effective date 1 November 2014), relating to the Walton Basin and Morant Basin consisting of blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a portion of block 1, offshore Jamaica, from 1 November 2017 (the "Effective Date") but subject to fulfilment by Tullow Jamaica and UOG Jamaica of their respective obligations under the agreement ("Closing").

From the Effective Date, but subject to Closing, the interests of the parties in the rights and obligations of the Contractor (as defined in the Contract), and the respective participating interests of the parties in the joint operating agreement to be entered into by the parties on the Closing Date, were to be:

Tullow Jamaica	80% and operator
UOG Jamaica	20%

The conditions precedent to transferring the Assigned Interest were:

(a) signature of a deed of assignment by the parties;

(b) the written approval of the government of Jamaica and the relevant consents being obtained;

(c) UOG Jamaica providing Tullow Jamaica with a parent company guarantee; and

(d) UOG Jamaica providing a parent company guarantee to the government of Jamaica, issued by UOG Jamaica's guarantor (being the Company).

The agreement recorded that if each of the above conditions precedent had not been satisfied on or before the date which is twelve months following the date of signature of this agreement (or such later date as the parties may agree in writing), then the agreement may be terminated by either party giving written notice to the other.

In consideration for the transfer of the Assigned Interest by Tullow Jamaica to UOG Jamaica, UOG Jamaica agreed to:

(a) pay to Tullow Jamaica at Closing an amount equal to the Assigned Interest share of the joint account expenses incurred between the Effective Date and the date of completion;

(b) pay to Tullow Jamaica an amount equal to the Assigned Interest share of the joint account expenses (including UOG Jamaica's share of the 3D seismic cost) from the date of completion (ground floor costs) under the Jamaica JOA; and

(c) provided Tullow Jamaica gives notification to the PCJ pursuant to the Contract and elects to proceed into the second exploration period of the Contract (as defined in the Contract), UOG Jamaica is to reimburse Tullow Jamaica for the equivalent of USD 350,000 of the documented past costs incurred by Tullow Jamaica in respect of the second sub-period of the initial exploration period (as defined in the Contract), within 30 days of such election notice.

The consideration referred to above is payable by UOG Jamaica at Closing.

During the period commencing on the Effective Date and up to and including the date of completion, Tullow Jamaica agreed to continue to, amongst other conditions:

(a) continue to hold the Assigned Interest in the ordinary and usual conditions of business and in accordance with the terms of the contract documents and good industry practice;

(b) keep UOG Jamaica informed of any material developments relating to the petroleum operations; and

(c) not, without UOG Jamaica's prior written consent, enter into any new material agreements in connection with the petroleum operations other than in the ordinary and usual course of business, and amend, agreed to amend, supplement, terminate, replace, withdraw from, voluntarily surrender or relinquish any rights under the contract documents.

Customary warranties, undertakings and indemnities for an agreement of this type were provided by the parties.

11.20 ***Optiva December 2017 Warrant Instrument***

Pursuant to the Optiva December 2017 Warrant Instrument constituted on 27 December 2017 and executed by the Company, the Company issued 1,375,000 Optiva December 2017 Warrants which each entitle Optiva to subscribe for 1 new Ordinary Shares at 4 pence per Ordinary Share for a period of five years from 20 December 2017. The Optiva December 2017 Warrants are unlisted, fully transferable and exercisable in whole or in part.

11.21 ***Deed of Assignment of Licence PL090 2018***

On 8 January 2018, Egdon, Aurora, UOG PL090, Corfe and Dorset assigned to Egdon, Aurora, UOG PL090 and Corfe all rights, interest, obligations and liabilities of PL090, with the consent of the OGA.

11.22 ***Deed of Collective Novation in respect of a joint operating agreement and a trust deed relating to the PL090 Licence***

On 8 January 2018, Egdon, Aurora, UOG PL090, Corfe and Dorset executed a deed of novation whereby Dorset ceased to be a party to (a) a trust agreement dated 26 March 2013 relating to the PL090 licence; and (b) the Area A JOA and Area B JOA, as referred to at paragraph 20.1.6 above. The 10 per cent. interest in the PL090 licence previously held by Dorset, was assigned to Egdon upon completion.

This deed records the post-transfer per cent. interests of the participants held under the Area A JOA and Area B JOA following execution of the deed as follows:

(a) Area A JOA

Egdon	55.00%
Aurora	18.75%
UOG PL090	26.25%
Total	100.00%

(b) Area B JOA

Egdon	42.5000%
Aurora	13.5417%
UOG PL090	18.9853%
Corfe	25.0000%
Total	100.0000%

11.23 ***Corallian Farmout Agreement***

On 15 January 2018, Corallian and UOG Colter entered into a farmout agreement, pursuant to which Corallian agreed to farm out to UOG Colter:

(a) a ten per cent. legal and beneficial interest (the "Initial Farmed Interest") in each of the Corallian Licences; or

(b) an additional ten per cent. legal and beneficial interest in each of the Corallian Licences (the "Additional Farmed Interest").

"Farmed Interest", as defined in the Corallian Farmout Agreement means the Initial Farmed Interest or the Additional Farmed Interest (as the context requires), and "Farmed Interests" means both of them.

As consideration for the Farmed Interest, UOG Colter agreed to:

(a) subject to (f) below, pay its percentage interest in the Corallian Licences ("Percentage Interest") share of all costs pursuant to the joint operating agreement between the holders of the Corallian Licences attributable to the Farmed Interest with effect from 1 February 2012 (the "Corallian Economic Date") and of all insurance costs; and

(b) subject to the (c) below, with effect from 15 January 2018 (the "Farmout Date"), pay an additional amount equivalent to 13.33 per cent. of the Farmed Interest's share of the costs charged to the joint account under the joint operating agreement in respect of the Colter Well, up to and including the point when the Colter Well has been permanently plugged and abandoned.

(c) In calculating the amount payable under (b) above, the applicable cost charged to the joint account under the joint operating agreement shall:

    (i) exclude the uplift charged pursuant to paragraph 3.2.12 of the accounting procedure to the joint operating agreement; and

    (ii) be limited to the total applicable share of total costs of the Colter Well of up to eight million pounds (£8,000,000) (excluding the uplift referred to above) and any costs above that shall be borne in proportion to the Percentage Interest shares under the joint operating agreement.

(d) For the avoidance of doubt, where the Colter Well preparations commenced before the Farmout Date then the costs of such work are included in the sums to which (b) and (c) above apply.

(e) Any other costs attributable to the Corallian Licences since 1 February 2017, such as licence fees and levies and reprocessing of seismic data, are borne in proportion to the Percentage Interest shares under the JOA. These costs will exclude those which relate to PEDL 330 and PEDL 345 Licences.

(f) The costs associated with PEDL 330 and PEDL 345 Licences incurred since 1 February 2017, and all other costs attributable to the Licences between the Corallian Economic Date and 1 February 2017 shall become payable 12 months after the Colter Well has been permanently plugged and abandoned but limited to a maximum of £56,250 net to UOG Colter if only the Initial Farmed Interest has been assigned to UOG Colter or £112,500 net to UOG Colter if both the Farmed Interests have been assigned to UOG Colter.

The agreement records that the Farmed Interests are subject to an agreement dated 23 February 2017 between Corallian and Infrastrata pursuant to which Corallian undertook to pay to Infrastrata sums in respect of profits made as a result of the production of petroleum from the P1918 Licence (the "NPI Agreement"). The agreement states that on completion of the assignments of the Farmed Interests, the NPI Agreement will be novated to provide that UOG Colter bears the applicable Farmed Interest's share of the obligations under the NPI Agreement.

Customary representations, warranties and indemnities for an agreement of this type were given by UOG Colter and Corallian.

In the event that before the work detailed at the second (b) bullet point above in this paragraph has been completed, UOG Colter fails without proper reason to make any payment due under clause 3.1 of this agreement, then Corallian may give UOG Colter notice of default and of its intention to terminate the agreement in accordance with the agreement. If the default is not remedied, Corallian can terminate the agreement and require UOG Colter to retransfer the Farmed Interests to it, without any consideration. Such transfer will not relieve the UOG Colter of liability to make payments under the agreement (pursuant to clause 3 of the agreement).

The agreement records that in the event a licensee of the Corallian Licences submits an application for the award of a petroleum licence over blocks defined within the area defined in Appendix A of this agreement ("AMI"), or acquires an interest in a licence in an AMI, then such licensee shall invite the other licensees to join in such application or acquisition on a ground-floor basis for a participating interest in the same ratio as the licensees have participating interest in the Corallian Licences. The AMI will apply for a period expiring 30 January 2022 or on the expiry of the Corallian Licences, whichever is the later.

11.24 ***Swift Option Agreement***

On 23 January 2018, the Company, Swift and Stelinmatvic (together, Swift and Stelinmatvic are the "Licence Holders") entered into an option agreement pursuant to which the Company was granted the opportunity to acquire from the licence holders a 24 per cent. interest in the P2264 licence (the "P2264 Participating Interest") as it relates to the area of block 49/29c which forms part of the licensed area of the of the P2264 licence (the "P2264 Farm-in Area").

With effect from the date of this agreement and in consideration of the Company agreeing to pay £40,000 on such date as the farm-in agreement whereby the Company acquires the P2264 Participating Interest setting out the respective responsibilities and obligations of the parties in respect of exploration of the P2264 Farm-in Area (the "P2264 Farm-in Agreement"), being a payment of £20,000 to each of the Licence Holders, each Licence Holder undertook that it would not at any time before 30 June 2018 or such other date as the OGA may specify as being an amendment to the 30 June 2018 date by which Swift will have negotiated a sale and purchase agreement, as specified in a letter dated 27 November 2017 from the OGA to Swift ("Expiry Date"), enter into any agreements with a third party/ies which would result in such Licence Holder retaining less than a 12 per cent. participating interest in the P2264 Farm-in Area.

The agreement records that subject to:

(a) a firm well commitment becoming applicable to the P2264 licence by no later than 31 August 2018 (or such later date as the OGA may permit);

(b) the parties agreeing all the terms of a farm-in agreement by no later than the Expiry Date; and

(c) obtaining all necessary consents and approvals under the P2264 licence,

The Company will be entitled to receive a transfer of the P2264 Participating Interest upon execution of the farm-in agreement. Each of the Licence Holders will contribute a 12 per cent. participating interest to such transfer of the P2264 Participating Interest, or such other percentage as the parties agree. Following completion of the transfer to the Company, the Company will contribute 30 per cent. towards the well costs. In the event that before the Expiry Date, no third party farmee or alternative means of funding 70 per cent. of the well costs is forthcoming, the Licence Holders have agreed to discuss with the Company whether it will wish to increase its 30 per cent. contribution.

11.25 ***Deed of Assignment and Assumption and Amendment Agreement No.5***

On 1 March 2018, Tullow Jamaica assigned to UOG Jamaica the Assigned Interest in the Contract. As a result of the assignment, UOG Jamaica agreed to accept the Assigned Interest and assume the obligations attendant with the Assigned Interest under the Contract.

11.26 ***Jamaica JOA***

On 1 March 2018, Tullow Jamaica and UOG Jamaica entered into the Jamaica JOA. The Jamaica JOA recorded that Tullow Jamaica had transferred the Assigned Interest to UOG Jamaica, and that the Jamaica JOA defined the respective rights and obligations concerning operations and activities under the Contract.

The Jamaica JOA continues in effect until:

(a) the Contract terminates;

(b) all materials, equipment and personal property acquired for or used in connection with joint operations or exclusive operations (as defined in the Jamaica JOA) have been disposed of or removed; and

(c) final settlement (including settlement of any financial audit carried out under the accounting procedure) has been made.

The parties can terminate the Jamaica JOA in certain situations, such as if they unanimously agree or they surrender the contract area.

The purpose of the Jamaica JOA was to establish the respective rights and obligations of the parties concerning the operations and activities under the Contract, including the joint exploration, appraisal, development and production of hydrocarbons (including treatment, storage and handling of produced hydrocarbons upstream of the delivery point), the determination of entitlements at the delivery point and decommissioning.

Tullow Jamaica was designated the operator under the Jamaica JOA, and agreed to have exclusive charge of the joint operations and conduct all joint operations, in the manner associated with an agreement of this type. Tullow Jamaica can resign as operator by notifying UOG Jamaica at least 120 days before the effective date of such resignation. Tullow Jamaica, as operator, can be removed upon receipt of notice from any non-operator (i.e. UOG Jamaica) in certain situations, including if it has committed a material breach of the Jamaica JOA, such as if Tullow Jamaica becomes insolvent or bankrupt or makes an assignment for the benefit of its creditors, if a receiver is appointed for a substantial part of Tullow Jamaica's assets or Tullow Jamaica dissolves, liquidates, winds up or otherwise terminates its existence.

In the event there is a change of operator, the joint operating committee will meet as soon as possible to appoint a successor operator pursuant to the voting procedure under the Jamaica JOA. If Tullow Jamaica is removed as operator, neither it or any affiliate of it shall have the right to be considered as a candidate for the successor operator.

Under the Jamaica JOA, a joint operating committee was to be established to provide for the overall supervision and direction of joint operations, consisting of a representative from each party holding a participating interest. Each party could appoint one representative and one alternative representative. The joint operating committee has the power and duty to authorise and supervise the joint operations that are necessary or desirable to fulfil the Contract and properly explore the contract area under the Jamaica JOA, the Contract, and applicable laws. Voting on all proposals is decided by the affirmative vote of two or more of the parties that are not affiliates having collectively at least 65 per cent. of the participating interests.

The operator is to deliver to the parties on or before 1 October each year, a proposed annual work program and budget, along with the estimated costs forecasts for the remainder of the calendar year. The Jamaica JOA also sets out the procedures to be followed by the operator and the parties if a commercial discovery is made that may lead to commercial production, and the procedures for the operator awarding contracts for joint operations during the various phases (including the obligations on the operator to provide certain information to the non-operators before any commitment or expenditure is made for a joint operation).

In the event a party fails to pay its share of joint account charges (including cash calls and interest), the Jamaica JOA sets out the rights that are lost by the defaulting party (for example, voting rights), and the allocations of the non-defaulting parties to pay their respective portions of the amount in default.

The Jamaica JOA sets out the rights of the parties in respect of their entitlement to own, take in kind or separately dispose of its quantity of hydrocarbons. If crude oil is to be produced from the development and production area, the parties will in good faith and not less than 90 days prior to the anticipated first delivery of crude oil, negotiate and conclude the terms of an offtake agreement.

11.27 *Deed of Guarantee*

On or around 1 March 2018, the Company agreed to execute and deliver to the PCJ a deed of guarantee in favour of the PCJ, to unconditionally and irrevocably guarantee the due and timely performance of UOG Jamaica's obligations under the Contract. Such obligations include UOG Jamaica's minimum expenditure obligation for the 3rd sub-period of the initial exploration period. The maximum aggregate liability of the Company is an amount equal to the sum of the minimum exploration expenditure for the 3rd sub-period, plus twenty-five per cent. of the minimum exploration expenditure for the 3rd sub-period. The guarantee remains in force until all obligations of UOG Jamaica for the 3rd sub-period of the initial exploration period have been discharged in full, or the obligations of UOG Jamaica have been terminated.

11.28 ***Parent Company Guarantee***

On 1 March 2018, the Company entered into a parent company guarantee in favour of Tullow Jamaica, to irrevocably and unconditionally guarantee to Tullow Jamaica the punctual observance and performance by UOG Jamaica of its obligations due and owing from, or otherwise incurred by, UOG Jamaica to Tullow Jamaica under the farmout agreement with Tullow Jamaica. Under this guarantee, the Company undertook that if UOG Jamaica did not pay any amount comprised in the guaranteed obligations when due to Tullow Jamaica, the Company would promptly pay on demand, but no later than ten business days from such demand, the amount to Tullow Jamaica.

11.29 ***2018 Placing Agreement***

On 26 April 2018, (1) the Company; (2) Beaumont Cornish; (3) Optiva; and (4) SP Angel Corporate Finance LLP ("SP Angel") entered into a placing agreement.

Under the placing agreement, Beaumont, Optiva and SP Angel agreed to act as agents to the Company for the placing, and Optiva and SP Angel agreed to use their reasonable endeavours (as agents of the Company) to procure subscribers for the Ordinary Shares at the placing price of 8 pence per Ordinary Share. In consideration for the services provided by Beaumont, Optiva and SP Angel, the Company agreed upon admission to:

(a) pay Beaumont:

   (i) a fee of £60,000, less any sums already paid to Beaumont in respect of this transaction;

(b) pay Optiva:

   (i) a commission of 5 per cent. of the aggregate value of the Ordinary Shares at 8 pence per Ordinary Share where placed by Optiva; and

   (ii) to issue warrants to Optiva pursuant to the Optiva April 2018 Warrant Instrument; and

(c) pay SP Angel:

   (i) a commission of 5 per cent. of the aggregate value of the Ordinary Shares at 8 pence per Ordinary Share where placed by SP Angel.

The Company gave certain customary warranties indemnities to Beaumont, Optiva and SP Angel.

11.30 ***Optiva April 2018 Warrant Instrument***

Pursuant to a warrant instrument dated 30 April 2018 and executed by the Company, the Company issued 2,728,126 Optiva April 2018 Warrants which each entitles Optiva to subscribe for 1 new Ordinary Share at the exercise price of 4.25 pence per share for a period of five years from admission. The Optiva April 2018 Warrants are unlisted, fully transferable and exercisable in whole or in part.

11.31 ***September 2018 Warrant Instrument***

Pursuant to a warrant instrument dated 18 September 2018 and executed by the Company, the Company created and granted 40,909,018 warrants to subscribe for Ordinary Shares. Each warrant entitled the holder to subscribe for 1 new Ordinary Share at the exercise price of 8 pence for a period commencing on 10 October 2019 and expiring on 8 October 2022.

11.32 ***September 2018 Placing Agreement***

On 18 September 2018, Stockdale Securities Limited ("Stockdale") and the Company entered into a placing agreement.

The placing agreement was conditional upon, amongst others, (i) the Company passing board resolutions by 7.00 a.m. on the date of the placing agreement to approve entry into the placing documents and conditional issuance and allotment of the placing shares, subscription shares and the September Placing 2018 Warrants, (ii) the resolutions set out in the circular of the company seeking approval of the resolutions relating to the placing, subscription and warrants and containing details of the placing and the notice of general meeting, being passed at the general meeting of the Company held on 8 October 2018, and (iii) admission taking place by not later than 8.00 a.m. on

10 October 2018 (or such later date as the Company and Stockdale may agree), but in any event not later than 31 October 2018.

Under the placing agreement, Stockdale agreed to act as agent to the Company for the placing and to use its reasonable endeavours (as agent of the Company) to procure placees for the new ordinary shares at the placing price. In consideration for the services provided by Stockdale, the Company agreed upon admission to pay Stockdale a fee of £20,000 as a placing agent fee.

The Company gave certain warranties as to the accuracy of the information contained in the presentation, placing letters, application, circular and announcement and other matters in relation to the Company and the business of the Group. The Company gave certain customary indemnities to Stockdale. Stockdale could terminate the placing agreement in certain specified circumstances prior to admission, principally in the event of a material breach of the placing agreement or any of the warranties contained in it, or any failure by the Company to comply with their obligations which was or would be in the opinion of Stockdale, materially prejudicial in the context of the placing.

11.33 ***Deed of Novation and Amendment of the NPI Agreement***

On 1 October 2018, Corallian, UOG Colter and Infrastrata entered into a deed of novation and amendment relating to the NPI Agreement pursuant to which with effect from 27 April 2018, Corallian is released and discharged from and UOG Colter agrees to assume the liabilities and performs the obligations of Corallian under or in respect of the NPI Agreement in respect of an 8 per cent. participating interest in the P1918 Licence. Accordingly, UOG Colter's participating interest in P1918 Licence consists of an 8 per cent. participating interest that is subject to the NPI Agreement and a 2 per cent. participating interest that is not so burdened.

11.34 ***Deed of Novation and Amendment of the NPI Agreement***

On 1 October 2018, Infrastrata, Westmount Energy Limited ("Westmount"), Corallian and UOG Colter entered into a deed of novation and amendment relating to the NPI Agreement pursuant to which with effect from 1 October 2018, Infrastrata will be released and discharged from and Westmount will assume the liabilities and perform the obligations of Infrastrata under or in respect of the NPI Agreement.

11.35 ***Deed of Variation of the P1918 Licence***

On 27 November 2018, Corallian, Corfe, UOG Colter and the OGA entered into a deed of variation which varies the P1918 Licence as follows:

(a) any reference to the "Initial Term" was a reference to the period of eight years beginning with 1 February 2012;

(b) any reference to the "Second Term" was a reference to the period of one year beginning immediately after the expiry of the period mentioned in paragraph (a) above;

(c) any reference to the "Third Term" was a reference to the period of 17 years beginning immediately after the expiry of the period mentioned in paragraph (b) above.

11.36 ***Deed of Novation and Amendment of the NPI Agreement***

On 12 December 2018, Corallian, UOG Colter, Baron and Westmount entered into a deed of novation and amendment relating to the NPI Agreement, pursuant to which Corallian agreed to assign Baron a Participating Interest (as defined in the NPI Agreement) of 6.4 per cent. (which was subject to the NPI Agreement), which prior to the assignment represented 16 per cent. of Corallian's obligations under the NPI Agreement (being in respect of a Relevant Percentage (as defined in the NPI Agreement) of 13.333 per cent. (the "Transferred Interest")). The parties agreed that Corallian was to be released and discharged from, and Baron was to assume the liabilities and perform the obligations of Corallian under or in respect of the NPI Agreement in respect of the Transferred Interest from the date of the deed.

11.37 ***Deed of Licence Assignment of the P1918 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3), ((1) through (3) are together the ("P1918 Assignors")), Baron (4) ((the Assignors and Baron are together the ("P1918 Assignees")) and the OGA (5) entered into a deed of licence assignment, pursuant to which the P1918 Assignors assigned to the P1918 Assignees all rights, interest, obligations and liabilities of the P1918 Assignors in, under, pursuant to and in respect of the P1918 Licence.

11.38 ***Restated and Amended Joint Operating Agreement in respect of the P1918 Licence***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a restated and amended joint operating agreement in respect of the P1918 Licence (the "P1918 JOA"), pursuant to which it was stated that the P1918 JOA was entered into by the parties for the purpose of regulating operations under the P1918 Licence and to define their respective rights, interests, duties and obligations in connection with the P1918 Licence and in connection with petroleum produced under the P1918 Licence. Furthermore, it was stated that the P1918 JOA corrected and replaced a similar agreement dated 5 February 2013 (as novated to Corallian, Corfe and UOG Colter).

11.39 ***Deed of Licence Assignment of the PEDL330 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3) ((1) through (3) are together the ("PEDL330 Assignors"), Baron (4) ((the PEDL330 Assignors and Baron are together the ("PEDL330 Assignees")) and the OGA (5) entered into a deed of licence assignment of the PEDL330 Licence, pursuant to which the PEDL330 Assignors assigned to the PEDL330 Assignees all rights, interest, obligations and liabilities of the PEDL330 Assignors in, under, pursuant to and in respect of the PEDL330 Licence;

11.40 ***Deed of Novation of the PEDL 330 Joint Operating Agreement***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a deed of novation of the PEDL330 joint operating agreement ("PEDL330 JOA"), pursuant to which:

(a) Corallian wished to be released and discharged from, and Baron wished to assume the liabilities and obligations under or in respect of the PEDL330 JOA in respect of the Baron Transferred Interest (as defined therein) and Corfe and United agreed to release and discharge Corallian upon and subject to the terms therein contained; and

(b) Corfe wished to be released and discharged from, and Corallian wished to assume the liabilities and obligations under or in respect of the PEDL330 JOA in respect of the Corfe Transferred Interest (as defined therein), and UOG Colter agreed to release and discharge Corfe upon and subject to the terms therein contained.

11.41 ***Deed of Licence Assignment of the PEDL345 Licence***

On 12 December 2018, Corallian (1), Corfe (2), UOG Colter (3) ((1) through (3) are together the ("PEDL345 Assignors"), Baron (4) ((the PEDL345 Assignors and Baron are together the ("PEDL345 Assignees")) and the OGA (5) entered into a deed of licence assignment of the PEDL345 Licence, pursuant to which the PEDL345 Assignors assigned to the PEDL345 Assignees all rights, interest, obligations and liabilities of the PEDL345 Assignors in, under, pursuant to and in respect of the PEDL345 Licence.

11.42 ***Deed of Novation of the PEDL345 Joint Operating Agreement***

On 12 December 2018, Corallian, Corfe, UOG Colter and Baron entered into a deed of novation of the PEDL345 joint operating agreement ("**PEDL345 JOA**"), pursuant to which:

(a) Corallian wished to be released and discharged from, and Baron wished to assume the liabilities and obligations under or in respect of the PEDL345 JOA in respect of the Baron Transferred Interest (as defined therein) and Corfe and United agreed to release and discharge Corallian upon and subject to the terms therein contained; and

(b) Corfe wished to be released and discharged from, and Corallian wished to assume the liabilities and obligations under or in respect of the PEDL345 JOA in respect of the Corfe Transferred

Interest (as defined therein), and UOG Colter agreed to release and discharge Corfe upon and subject to the terms therein contained.

12. LITIGATION

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened) of which the Company is aware, which may have or have had during the 12 months immediately preceding the date of this Document a significant effect on the financial position or profitability of the Company or the Group.

13. WORKING CAPITAL

In the opinion of the Directors, having made due and careful enquiry, the working capital available to the Company and the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of Admission.

14. TAKEOVER CODE

14.1 *Mandatory takeover bids*

The Company is subject to the Takeover Code. Brief details of the Panel, the Takeover Code and the protections they afford are described below. The Takeover Code is issued and administered by the Panel. The Takeover Code applies to all takeover and merger transactions, however effected, where the offeree company is, *inter alia*, a listed public company resident in the United Kingdom. The Company is a public company resident in the United Kingdom and its shareholders are therefore entitled to the protections afforded by the Takeover Code. Under Rule 9 of the Takeover Code, where any person acquires, whether by a series of transactions over a period of time or not, an interest in shares (as defined in the Takeover Code) which (taken together with shares already held by him and any interest in shares held or acquired by persons acting in concert with him) carry 30 per cent. or more of the voting rights of a company, that person is normally required to make a general offer to all the holders of any class of equity share capital or other class of transferable securities carrying voting rights in that company to acquire the balance of their interests in the company. Rule 9 of the Takeover Code also provides that, among other things, where any person who, together with persons acting in concert with him, is interested in shares which in aggregate carry not less than 30 per cent. of the voting rights of a company but does not hold shares carrying more than 50 per cent. of the voting rights of such a company, and such person, or any person acting in concert with him, acquires an additional interest in shares which increases the percentage of shares carrying voting rights in which he is interested, then such person is normally required to make a general offer to all the holders of any class of equity share capital or other class of transferable securities carrying voting rights of that company to acquire the balance of their interests in the company.

An offer under Rule 9 of the Takeover Code must be in cash (or with a cash alternative) and at not less than the highest price paid within the preceding twelve months for any shares in the company by the person required to make the offer or any person acting in concert with him. Rule 9 of the Takeover Code further provides, among other things, that where any person who, together with persons acting in concert with him holds over 50 per cent. of the voting rights of a company, acquires an interest in shares which carry additional voting rights, then they will not generally be required to make a general offer to the other shareholders to acquire the balance of their shares. However, individual members of a concert party will not be able to increase their percentage interest in shares through or between a Rule 9 threshold without Panel consent. For the purposes of the Takeover Code, persons acting in concert comprise persons who, pursuant to an agreement or understanding (whether formal or informal), co-operate to obtain or consolidate control of a company. Paragraph (9) of the definition of 'acting in concert' also deems any shareholders in a private company who sell their shares in that company in consideration for the issue of new shares in a company to which the Takeover Code applies to be acting in concert for the purposes of the Takeover Code unless the contrary is established.

14.2 ***Squeeze out***

Under the Act, if a "**takeover offer**" (as defined in section 974 of the Act) is made for the Ordinary Shares and the offeror were to acquire, or unconditionally contract to acquire, not less than 90 per cent. in value of the Ordinary Shares to which the takeover offer relates (the "**Takeover Offer Shares**") and not less than 90 per cent. of the voting rights attached to the Takeover Offer Shares within three months of the last day on which its offer can be accepted, it could acquire compulsorily the remaining 10 per cent. It would do so by sending a notice to outstanding Shareholders telling them that it will acquire compulsorily their Takeover Offer Shares and then, six weeks later, it would execute a transfer of the outstanding Takeover Offer Shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for the outstanding Shareholders. The consideration offered to the Shareholders whose Takeover Offer Shares are acquired compulsorily under the Act must, in general, be the same as the consideration that was available under the takeover offer.

14.3 ***Sell-out***

The Act also gives minority Shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer relates to all the Ordinary Shares and at any time before the end of the period within which the offer could be accepted the offeror holds or has agreed to acquire not less than 90 per cent. of the Ordinary Shares (being voting shares that carry voting rights in the Company), any holder of Ordinary Shares to which the offer relates who has not accepted the offer is entitled by a written communication to the offeror to require it to acquire its Ordinary Shares. The offeror is required to give any Shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of the minority Shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or, if later, the giving notice. If a Shareholder exercises his other rights, the offeror is bound to acquire those Ordinary Shares on the terms of the offer or on such other terms as may be agreed.

15. COMPETENT PERSONS

15.1 The Competent Persons have confirmed to the Company and Beaumont Cornish that: (i) they have reviewed the information that relates to the information contained in the Competent Persons' Reports in this Document, set out in Parts VIII and IX, which is contained in a portion of this Document other than in such report; and (ii) such information contained in a portion of this Document other than such report is, to the best of the Competent Persons' knowledge, correct on its facts, accurate, balanced, complete, not inconsistent with such report and contains no material omissions likely to affect its import.

15.2 The Competent Persons have no material interests in the Company.

16. GENERAL

16.1 The total costs and expenses relating to the Admission payable by the Company are estimated to be approximately £252,500 (excluding VAT).

16.2 UHY Hacker Young LLP of Quadrant House, 4 Thomas More Square, London E1W 1YW has given and not withdrawn its written consent to the inclusion in this Document of references to its name in the form and context in which they appear.

16.3 Beaumont Cornish has given and not withdrawn its written consent to the inclusion in this Document of references to its name in the form and context in which they appear.

16.4 Optiva Securities has given not withdrawn its written consent to the inclusion in this Document of references to its name in the form and context in which they appear.

16.5 ERC Equipoise Ltd has given and not withdrawn its consent to the issue of this Document with inclusion in it of their reports as set out in Part VIII of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports. ERC Equipoise Ltd has also confirmed to the Company and Beaumont Cornish that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in the Competent Person's Report since the effective date of such report.

16.6 CGG Service (UK) Limited has given and not withdrawn its consent to the issue of this Document with inclusion in it of their reports as set out in Part IX of this Document and the references thereto and to their name in the form and context in which they appear and have accepted responsibility for the content of such reports. CGG Service (UK) Limited has also confirmed to the Company and Beaumont Cornish that, to the best of its knowledge and belief, there has been no material change in circumstances to those stated in the Competent Person's Report since the effective date of such report.

16.7 The accounting reference date of the Company is 31 December.

16.8 The Directors are unaware of any exceptional factors which have influenced the Company's activities.

16.9 There are no patents or other intellectual property rights, licences or particular contracts which are or may be of fundamental importance to the Company's business.

16.10 Save as disclosed in this Document, the Company has no principal investments in progress and there are no principal investments on which the Company has made a firm commitment.

16.11 Other than as disclosed in this Document, there have been no significant changes in the trading or financial position of the Company since 31 December 2017, being the date to which the last audited accounts were made up.

16.12 CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by written instrument. The Articles permit the holding and transfer of shares under CREST. The Company has applied for the issued Ordinary Shares to be admitted to CREST and it is expected that the issued Ordinary Shares will be so admitted, and accordingly enabled for settlement in CREST.

16.13 Save as disclosed in this Document, no person directly or indirectly (other than the Company's professional advisers and trade suppliers or as disclosed in this Document) in the last 12 months received or is contractually entitled to receive, directly or indirectly, from the Company on or after Admission any payment or benefit from the Company to the value of £10,000 or more or securities in the Company to such value or entered into any contractual arrangements to receive the same from the Company at the date of Admission.

16.14 Where information which appears in this Document has been sourced from a third party, the information has been accurately reproduced. As far as the Directors and the Company are aware and able to ascertain from such information supplied or published by a third party, no facts have been omitted which would render any reproduced information false, inaccurate or misleading.

16.15 Save as disclosed in this Document, there are no known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects for at least the current financial year.

17. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents may be inspected at the registered office of the Company during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of this document until one month following Admission:

17.1 the memorandum and articles of association of the Company;

17.2 the audited accounts of the Group for the financial year ended 31 December 2017 as outlined in Part IV; and

17.3 this Document.

18. AVAILABILITY OF THIS DOCUMENT

Copies of this Document are available free of charge from the Company's registered office and from the offices of Beaumont Cornish, 10th Floor, 30 Crown Place, London EC2A 4EB during normal business hours on any weekday (Saturdays and public holidays excepted) and shall remain available for at least one month after Admission. An electronic version of this Document can be downloaded from the Company's website: www.uogplc.com.

22 February 2019

PART VIII

COMPETENT PERSON'S REPORT – ERC EQUIPOISE LTD

22nd February 2019

The Directors
United Oil & Gas Plc
200 Strand
London
WC2R 1DJ

Beaumont Cornish Limited
10th Floor
30 Crown Place
London
EC2A 4EB

Executive Summary of the Evaluation of certain Contingent and Prospective Resources of United Oil & Gas Plc.

Dear Sirs,

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a competent person's report ("CPR") in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM Guidance Note"). Accordingly, ERCE reviewed certain Contingent and Prospective Resources associated with assets owned by United Oil & Gas Plc ("United Oil & Gas", "UOG" or the "Company") in licences PL090 onshore UK, P1918 offshore UK, P2264 offshore UK Southern North Sea, P2366 offshore UK and the Walton-Morant licence offshore Jamaica and reports herein said Contingent and Prospective Resources as at 22nd February 2019, being the date to which ERCE reviewed data made available to them. This is the effective date of this report, and ERCE is not aware of any material change in the status of the UOG assets in the period between the receipt of the data and the completion of the CPR. ERCE hereby consents to its inclusion in the Admission Document and also to using references to the CPR in any applicable disclosure document, provided that no portion be used out of context or in such a manner as to convey a meaning which differs from that set out in the whole. The CPR may not be used for any other purpose without the prior written approval of a Director of ERCE.

This CPR provides an update to the report prepared for UOG in April 2018, specifically to resources within the Waddock Cross field licence PL090 and the Colibri prospect, Walton-Morant licence. This is the first CPR that has been conducted for UOG on the Crown discovery, licence P2366, Blocks 15/18d and 15/19b offshore UK.

ERCE has carried out this work using the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Section 4 of the attached report. The full text can be downloaded from https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf. Nomenclature that may be used in this letter and the enclosed report is summarised in Section 5.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. No site visit was undertaken in the preparation of this report. ERCE has relied upon information provided by UOG for the preparation of its estimates of Contingent and Prospective Resources.

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR or on Admission and ERCE will receive no other benefit for the preparation of this CPR. ERCE does not have any pecuniary or other interests that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the resources and reserves and the projections and assumptions included in the various technical studies completed by the Company, opined upon by ERCE and reported herein.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in the Company, the Mineral Assets or Beaumont Cornish Limited ("Beaumont"), or any other economic or beneficial interest (present or contingent) in any of the assets being reported on. ERCE is not a group, holding or associated company of the Company or Beaumont. None of ERCE's partners or officers are officers or proposed officers of any group, holding or associated company of the Company or Beaumont.

The Competent Person involved in the preparation of this CPR is not an officer, employee or proposed officer of the Company or any group, holding or associated company of the Company or Beaumont. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of the Company, its directors, senior management and Beaumont.

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented herein are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees. In the case that material is delivered in digital format, ERCE does not accept any responsibility for edits carried out after the product has left the company's premises.

Contingent Resources

The Waddock Cross oil field, in which UOG has a 26.25% interest (Table 4), is located in licence PL090, in the Wessex Basin onshore UK, to the west of the Wytch Farm oil field. It contains oil within the

Jurassic Bridport Sandstone reservoir, and has historically undergone production, curtailed due to high water cut. The field is currently shut in. The operator, Egdon Resources UK Limited (“Egdon”), is investigating the restoration of production, via the drilling of one or more horizontal wells in a structurally higher area of the field. A revised reprocessing of the existing 3D seismic dataset that covers the Waddock Cross field has recently been completed; this latest reprocessing focused on addressing the apparent statics issues. The new PSTM and PSDM seismic volumes have been used to update the Waddock Cross structural interpretation and associated models of top reservoir depth structure, which are being assessed to determine the optimal location for the development wells. ERCE has reviewed the recently reprocessed time and depth seismic data and has adopted the new time and depth seismic data as the basis for our seismic interpretation. ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. Development is contingent on the preparation and the commitment to a commercial development plan. UOG estimates the chance of development (“Pd”) to be 75% which would likely involve the drilling of two new wells with any water being reinjected. The oil would be evacuated by road. ERCE has reviewed the estimated chance of development and consider this to be a fair assessment. There are no identified Reserves.

The Colter discovery, in which UOG has a 10% interest (Table 4), is located in licence P1918 (Block 98/11a) in the Wessex Basin offshore UK, to the south of the Wytch Farm oil field. Interpretation of the top reservoir structure is challenging and there is uncertainty associated with both the presence and location of a northwest to southeast trending fault that segments the discovery into Colter East and Colter West. Reprocessing of the 3D seismic survey covering the Colter discovery was completed in April 2018. However, the new seismic image has not changed the current interpretation of the fault nor the associated uncertainty in its position.

Colter East was discovered by Well 98/11-3 in 1986. The well encountered a 10.5 m section of the Sherwood Sandstone reservoir with oil saturations from logs up to 60%, underlain by water-bearing Sherwood Sandstone. A DST was performed on Well 98/11-3, with 8.5 stb of oil produced at surface out of 109 bbl total fluid influx, including water. The operator, Corallian Energy Limited ("Corallian") has been issued the relevant regulatory consents, performed a site survey and contracted the Ensco 72 jack-up drilling unit to drill an up-dip appraisal well. Drilling commenced on the 6th February 2019 and is expected to take approximately three weeks to reach a planned total depth of 1,830 meters. ERCE attributes Contingent Resources (sub-classification Development Pending) to Colter East. The contingencies include the success of the updip appraisal well and the commitment to, and preparation of a commercial development plan. UOG estimates the chance of development to be 75%. ERCE has reviewed the estimated Pd and consider this to be an appropriate assessment.

The Crown discovery, in which UOG has a 95% interest (Table 4) and is licence administrator, is located in licence P2366 and straddles Blocks 15/18d and 15/19b located at the north west margin of the Witch Ground Graben, offshore the United Kingdom. Crown was discovered by Well 15/19-9 in 1998. The well encountered in excess of 200 ft of good quality Balmoral Sandstone reservoir of Palaeocene age. The discovery has an oil rim of thickness between 35 and 55 ft overlain by gas and underlain by water-bearing sandstone. Wireline log oil saturations of up to 80% are encountered. ERCE attributes Contingent Resources (sub-classification Development Unclarified) to Crown. Development is contingent on the preparation and the commitment to a commercial development plan. UOG estimates the chance of development to be 40%. ERCE has reviewed the estimated Pd and consider this to be an appropriate assessment.

ERCE's estimates of the unrisked oil Contingent Resources in the Waddock Cross, Colter and Crown discoveries, both gross and net to UOG, are shown in Table 1.

Table 1: Unrisked Oil Contingent Resources, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%
PL1918	Colter East	Corallian Energy Limited	1.68	4.08	10.12	10.00%	0.17	0.41	1.01	75%
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	40%

Notes:

1) *"Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.*
2) *"Net Contingent Resources" are UOG's working interest fraction of the gross Contingent Resources*
3) *Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.*
4) *The volumes reported here are unrisked in that they have not been multiplied by a chance of development (Pd).*
5) *In accordance with SPE PRMS*

Prospective Resources

The PL090 partnership is maturing prospectivity within the greater licence area, and identifies a number of undrilled exploration prospects and leads. The licence is located in Wessex Basin onshore UK, to the west of the Wytch Farm oil field. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil Prospective Resources and Geological Chance of Success for the Broadmayne prospect, which is currently the most mature. Part of the Broadmayne structure is mapped as extending outside licence PL090. Reprocessing of the 3D seismic survey covering the Broadmayne prospect has recently been completed and preliminary interpretation supports the overall trapping mechanism and lateral extent of the historical mapping. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has reduced the element of trap risk, which results in a higher chance of success, compared to the assessment presented in 2017.

In Licence P1918 (Table 4), the Colter West prospect is separated from Colter East by a northwest to southeast trending fault. Well L98/06-M18Z, known as Old Harry, was drilled on the margins of the closure of Colter West in 2000. Log analysis indicates the presence of thin potentially hydrocarbon-bearing sands near the top of the Sherwood reservoir, underlain by water. No tests were undertaken. ERCE has assessed the Prospective Resources and Geological Chance of Success for Colter West updip of the Old Harry well.

Licence P2264 is located offshore UK in the Southern North Sea (Block 49/29c), and contains the undrilled Acle prospect, south of the Gawain field and due west of the North Davy field. UOG has agreed to an option to farm-in for a 24% interest (Table 4), executable upon a firm commitment being made to drill the well becoming applicable to the licence and a farm-in agreement being agreed. The option is valid until expiry of the licence, which will be no earlier than 28 February 2019, to cover the status of the extension. The target Rotliegend sandstone reservoir is proven in this area of the

Southern North Sea. Four wells drilled in the nearby area have all encountered the Rotliegend reservoir. The Acle prospect comprises a tilted fault block and ERCE has made an assessment of the Prospective Resources and Geological Chance of Success for this structure.

The Walton-Morant licence in which UOG holds a 20% interest (Table 4) is situated offshore Jamaica and covers an area of 32,065km^2. Historically, exploration in Jamaica focused on Cretaceous targets and to date nine onshore wells and two offshore wells have been drilled, the most recent of which was drilled in 1983. All but one of these wells exhibited hydrocarbon shows, which coupled with observed onshore and offshore seeps, suggests an active source kitchen.

The principal offshore exploration target identified by the operator, Tullow Jamaica Ltd ("Tullow"), is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20% porosity at outcrop. The Guy's Hill formation is a fluvio-deltaic-shallow marine succession of up to 320 m gross thickness onshore, and is capped by regional shales and marls. Well Arawak-1 is the nearest offshore penetration of the Guy's Hill formation located approximately 70 km to the west of the Calibri prospect. Tullow has identified a number of undrilled prospects and leads, of which the Colibri prospect is currently the most mature. The prospect lies in water depths of approximately 750 m and is a fault-bounded structure prognosed to contain Guy's Hill formation reservoir. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data, including coverage of the Colibri prospect. These data have been reprocessed, and a number of stacked volumes and derived attributes have been generated. These volumes form the basis for the interpretation and ERCE's updated estimation of Prospective Resources.

A summary of UOG's licence interests are presented in Table 4.

ERCE's estimates of the gross unrisked oil Prospective Resources in Broadmayne, Colibri and Colter West, and the net unrisked and risked Prospective Resources attributable to UOG based on its working interest are shown in Table 2, including estimates of Geological Chance of Success.

ERCE's estimates of the gross unrisked gas Prospective Resources in the Acle prospect and the net unrisked and risked Prospective Resources attributable to UOG based on its working interest are shown in Table 3, including estimates of Geological Chance of Success.

Conclusions

ERCE's conclusions are included within this Executive Summary section.

Table 2: STOIIP and Oil Prospective Resources, Gross and Net Attributable to UOG

Licence	Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest	Net Unrisked Prospective Resources (MMstb)				COS	Net Risked Prospective Resources (MMstb)			
			Low	Best	High	Mean	1U	2U	3U	Mean		1U	2U	3U	Mean		Low	Best	High	Mean
Walton Morant	Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%	6.1	25.5	102.5	45.8	20%	1.19	5.00	20.08	8.97
PL1918	Colter West	Corallian Energy Limited	15	38	95	49	4	11	29	15	10%	0.43	1.13	2.87	1.47	50%	0.22	0.56	1.44	0.74
PL090	Broadmayne	Egdon Resources UK Limited	5	11.1	24.5	13.4	1.5	3.3	7.4	4	18.95%	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

**Broadmayne's Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimates to lie within the PL090 block boundary (50%).*

Table 3: GIIP and Gas Prospective Resources, Gross and Net Attributable to UOG

Licence	Prospect	Operator/ Administrator	GIIP (Bcf)				Gross Unrisked Prospective Resources (Bcf)				*Working Interest	Net Unrisked Prospective Resources (Bcf)				COS	Net Risked Prospective Resources (Bcf)			
			Low	Best	High	Mean	1U	2U	3U	Mean		1U	2U	3U	Mean		Low	Best	High	Mean
P2264	Acle	United Oil & Gas Plc	57	132	301	163	42	99	226	122	24%	10	24	54	29	43%	4.4	10.2	23.3	12.6

**Acle Net Unrisked and Risked Prospective Resources assume execution of the Option Agreement to Farm into Licence P2264 to acquire a 24% interest*

Notes:

1) *Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.*
2) *"Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from an accumulation.*
3) *"Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources.*
4) *"Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).*
5) *The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.*
6) *Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).*
7) *In accordance with SPE PRMS.*

Table 4: Summary of United Oil and Gas Licence Interests

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19 km^2	
		UOG PL090 Ltd	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	201.9 km^2	
		UOG PL090 Ltd	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				
P1918 (Colter)	Corallian Energy Limited	Corallian Energy Limited	49.00%	Extant	31/1/2019 (Update on extension) 31/1/2020 (Second Term) 31/1/2038 (Licence End Date)	36.2 km^2	
		UOG Colter Ltd	10.00%				
		Corfe Energy Limited	25.00%				
		Baron Oil	8.00%				
		Reolute Oil & Gas	8.00%				
P2264* (Acle)	Swift Exploration Limited	Swift Exploration Limited	38.00%	Extant	28/02/2019 (Farm-in notification to OGA) 30/11/2019 (Initial Term) 30/11/2022 (Second Term) 30/11/2040 (Anticipated End Date)	29.01 km^2	An extension to the deed of variation granted on the 27th Nov 2018 has been awared extending the date by which a legally binding farm-in agreement must be executed to 28 Feb 2019, and the expiry of the Initial term of the Licence (30 Nov 2019)
		Stelinmatvic Industries Ltd	38.00%				
		United Oil & Gas Plc	24.00%				
Walton Morant (Colibri)	Tullow Jamaica Ltd	Tullow Jamaica Ltd	80.00%	Extant	2024	32,065 km^2	60% relinquishment, drill or drop 2019
		UOG Jamaica Ltd	20.00%				
P2366 (Crown)	United Oil and Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/09/2021 (Phase A) 30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)	13.6 km^2	Phase A work commitments include the reprocessing of 40km^2 of 3D seismic and an associated Rock Physics study. Phase C will start on the condition that there is a firm commitement to drilling a well.
		Swift Exploration Limited	5.00%				

**UOG's interest in Licence P2264 is subject to execution of a Farm-in Agreement. The initial term of the licence expires at the end of November 2019, However the current operator, Swift, is committed to inform the Oil and Gas Authority ("OGA") by 28th February 2019 of the companies that have agreed a farm-in to the block that will result in the drilling of a firm well. OGA approval will be required to extend beyond this date. If insufficient progress has been made by this date, there is a possibility that Swift will be forced to relinquish the block.*

UOG also hold interests in UK onshore licences PEDL330 and PEDL345 with the same equities as licence P1918. However, evaluation is at an early stage and no leads have yet been identified, therefore these licences have not been addressed as part of this document.

Confirmations and Professional Qualifications

In accordance with UOG's instructions to us ERCE confirms that:

- Mr Simon McDonald, Founder Director of ERCE, a Chartered Engineer and the President of The Society of Petroleum Evaluation Engineers (SPEE), who has over 40 years' experience in the evaluation of oil and gas fields and acreage, preparation of development plans and assessment of reserves and resources, was responsible for supervising this evaluation
- the SPEE is a self-regulating organisation of petroleum engineers and geologists specialising in reservoir evaluations
- ERCE personnel involved with this report have at least five years' relevant experience in the estimation, assessment and evaluation of oil and gas assets;
- it is independent of UOG ("the Company"), its directors, senior management and advisers;
- it has no economic or beneficial interest (present or contingent) in the Company or in any of the mineral assets evaluated and is not remunerated by way of a fee that is linked to the admission or value of the Company;
- Simon McDonald is not a sole practitioner;
- it accepts responsibility for the information contained in this section of the Admission Document and those sections of the Admission Document which include references to the

information in this section. ERCE and Simon McDonald declare that to the best of our knowledge and belief, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information.

Consent

We hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;
- the filing of this report with the AIM UK stock exchange and
- the electronic publication of this report on websites accessible by the public, including a website of the Company.

Yours faithfully

ERC Equipoise Limited

Simon McDonald
Founder Director, ERC Equipoise Ltd.

Evaluation of Certain Contingent and Prospective Resources of United Oil & Gas Plc

(Source: Egdon)

PREPARED FOR: United Oil & Gas Plc

BY: ERC Equipoise Limited

Month: February

Year: 2019

ERCE

Approved by: Simon McDonald

Date released to client: 22nd February 2019

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1. Introduction

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a competent person's report ("CPR") with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM Guidance Note").

Accordingly, ERCE reviewed certain Contingent and Prospective Resources associated with assets owned by United Oil & Gas Plc ("United Oil & Gas" or "UOG") in licence PL090 onshore UK, licence P1918 offshore UK, licence P2366 offshore UK, licence P2264 UK Southern North Sea and the Walton-Morant licence offshore Jamaica. ERCE reports herein said Contingent and Prospective Resources as at 7th January 2019, being the date to which ERCE reviewed data made available to us. This is the effective date of this report, and ERCE is not aware of any material change in the status of the UOG assets in the period between the receipt of the data and the completion of the CPR.

The licence interests assessed in this report are summarised in Table 1.1.

UOG acquired its interest in the PL090 licence through the acquisition of the assets of First Oil's subsidiaries in August 2016. UOG holds a 26.25% working interest in the Waddock Cross field area (approximately 19 km^2) and a working interest of 18.9541% in the remainder of the licence (approximately 183 km^2). Both areas are operated by Egdon Resources UK Limited ("Egdon") and expire on the 31 March 2024. There are no outstanding work commitments on the PL090 licence.

UOG acquired a 10% stake in the P1918 licence (approximately 36 km^2) from the operator Corallian Energy Limited ("Corallian") in January 2018. A well planned for Q1 2019 to appraise the Colter discovery made by Well 98/11-3 in the Sherwood Sandstone, which will satisfy the current work commitments, is underway. Drilling commenced on the 6th February 2019 and is expected to take approximately three weeks to reach a planned total depth of 1,830 meters.

UOG has agreed an option to farm-in to offshore Block 49/29c UK Licence P2264 which is jointly owned by Swift Exploration Limited ("Swift") (50%) and Stelinmatvic Industries Ltd ("Stelinmatvic") (50%). On exercise of the option UOG will take a 24% interest in the licence, being 12% from each of Swift and Stelinmatvic. For the combined 24% interest UOG will pay 30% of the costs associated with the drilling of the first exploration well. In addition, United will pay £20,000 in cash to each partner on signing of the farm-in agreement. The option to acquire the interest is subject to a drilling commitment becoming applicable to the licence and a farm-in agreement being agreed. The option is valid until expiry of the licence, which will be no earlier than 28th February 2019.

In August 2018 as part of the UK 30th offshore licencing round, UOG was awarded a 95% stake of offshore Blocks 15/18d and 15/19b, Licence P2366. The remaining 5% interest is owned by Swift. Work commitments involve the reprocessing of 40km^2 of 3D seismic and undertaking a rock physics study to help de-risk the Crown discovery. The initial phase of the licence will expire on 30 September 2021. A further phase can be entered into subject to the condition that a firm commitment to drilling a well has been made. If entered into, this subsequent phase will expire on the 30 September 2023.

UOG has signed an agreement with Tullow Jamaica Limited ("Tullow") to farm-in to the Walton-Morant Licence which covers an area of 32,065 km^2, offshore Jamaica at a 20% equity interest. This will involve paying a 20% share of costs from 1 November 2017. In May 2018, the acquisition of 2250 km^2 of 3D seismic data was successfully completed. This has been used to help delineate the Colibri prospect ahead of a drill or drop decision in 2019. Licence expiry occurs 2023. The deal has now been approved by the Petroleum Corporation of Jamaica ("PCJ") and completed on the 1 March 2018.

Table 1.1: Summary of UOG Licence Interests

License block	Operator / Administrator	Company	Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
PL090 (Waddock Cross)	Egdon Resources UK Limited	Egdon Resources UK Limited	55.00%	Extant	31/03/2024	19 km^2	
		UOG PL090 Ltd	26.25%				
		Aurora Exploration (UK) Ltd	18.75%				
PL090 (Exploration: Broadmayne)	Egdon Resources UK Limited	Egdon Resources UK Limited	42.50%	Extant	31/03/2024	201.9 km^2	
		UOG PL090 Ltd	18.95%				
		Aurora Exploration (UK) Ltd	13.54%				
		Corfe Energy Limited	25.00%				
P1918 (Colter)	Corallian Energy Limited	Corallian Energy Limited	49.00%	Extant	31/1/2019 (Update on extension) 31/1/2020 (Second Term) 31/1/2038 (Licence End Date)	36.2 km^2	
		UOG Colter Ltd	10.00%				
		Corfe Energy Limited	25.00%				
		Baron Oil	8.00%				
		Reolute Oil & Gas	8.00%				
P2264* (Acle)	Swift Exploration Limited	Swift Exploration Limited	38.00%	Extant	28/02/2019 (Farm-in notification to OGA) 30/11/2019 (Initial Term) 30/11/2022 (Second Term) 30/11/2040 (Anticipated End Date)	29.01 km^2	An extension to the deed of variation granted on the 27th Nov 2018 has been awared extending the date by which a legally binding farm-in agreement must be executed to 28 Feb 2019, and the expiry of the Initial term of the Licence (30 Nov 2019)
		Stelinmatvic Industries Ltd	38.00%				
		United Oil & Gas Plc	24.00%				
Walton Morant (Colibri)	Tullow Jamaica Ltd	Tullow Jamaica Ltd	80.00%	Extant	2024	32,065 km^2	60% relinquishment, drill or drop 2019
		UOG Jamaica Ltd	20.00%				
P2366 (Crown)	United Oil and Gas Plc	United Oil & Gas Plc	95.00%	Extant	30/09/2021 (Phase A) 30/09/2023 (Phase C) 30/09/2045 (Anticipated End Date)	13.6 km^2	Phase A work commitments include the reprocessing of 40km^2 of 3D seismic and an associated Rock Physics study. Phase C will start on the condition that there is a firm commitement to drilling a well.
		Swift Exploration Limited	5.00%				

**UOG's interest in Licence P2264 is subject to execution of a Farm-in Agreement. The initial term of the licence expires at the end of November 2019, However the current operator, Swift, is committed to inform the Oil and Gas Authority ("OGA") by 28th February 2019 of the companies that have agreed a farm-in to the block that will result in the drilling of a firm well. OGA approval will be required to extend beyond this date. If insufficient progress has been made by this date, there is a possibility that Swift will be forced to relinquish the block.*

UOG also hold interests in UK onshore licences PEDL330 and PEDL345 with the same equities as licence P1918. However, evaluation is at an early stage and no leads have yet been identified, therefore these licences have not been addressed as part of this document.

1.1. Data Provided

ERCE has relied upon data and information made available by UOG in the preparation of this report.

1.1.1. Waddock Cross and Broadmayne (PL090)

UOG provided two 3D seismic data sets, the Waddock Cross 3D (which covers the extent of the Waddock Cross field) and the Broadmayne 3D which covers the Broadmayne structure and several additional leads. In addition to seismic data ERCE has also received well results, wireline logs and CPIs thereof, well test reports, MDT and PVT data and production and pressure data for the Waddock Cross field.

The Waddock Cross 3D has recently been reprocessed and ERCE has been provided with a PSTM (time domain) and PSDM (depth domain) seismic volume. In addition, ERCE has taken receipt of revised time and depth interpretation from both UOG and the operator Egdon.

1.1.2. Colter (P1918)

Our review was undertaken using primary geotechnical data supplied by UOG. These comprise 3D seismic data, including structural interpretation in time and depth, together with open-hole logs.

1.1.3. Acle (P2264)

ERCE been given access to geotechnical data supplied by UOG. A review of the seismic data was performed through a data room at the premises of Swift. A Kingdom Project including structural interpretation in time and depth together with well data were also made available.

1.1.4. Colibri (Walton-Morant)

ERCE has been given access to a Petrel Project containing both well and seismic data through a data room in Tullow's offices. The seismic contained Tullow's recently acquired 2D lines and a mix of other vintage 2D lines. The project also contained a velocity model and time and depth interpretations performed by both Tullow and UOG.

Subsequent to the successful acquisition of 2250 km^2 of 3D seismic data in May 2018, ERCE has been provided with derived 3D time domain seismic volumes. In addition, ERCE has taken receipt of revised time and depth interpretations from both UOG and Tullow.

1.1.5. Crown (P2366)

ERCE has been given access to a Kingdom Project containing both well and seismic data. In addition, a well database has also been provided. This primarily contains scanned or digital reports, but several wells also have digital log data.

No site visit was undertaken in the preparation of this report.

1.2. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes.

1.2.1. Contingent Resources

1.2.1.1. Waddock Cross Field (PL090)

The Waddock Cross field is located in the Wessex Basin, onshore UK, to the west of the Wytch Farm and Wareham oil fields. The field contains 29° API oil within the Jurassic Bridport Sandstone reservoir, and has historically undergone oil production, which was suspended due to a high water cut. The field is currently shut in.

The Waddock Cross 3D has recently been reprocessed with a focus on addressing apparent near-surface statics issues. This has given rise to both PSTM (time domain) and PSDM (depth domain) seismic volumes. The new volumes have only recently been interpreted and further studies are being undertaken to determine the viability and optimal location for any new well(s).

ERCE attributes Contingent Resources (sub-classification Development Pending) to the Waddock Cross field associated with this potential redevelopment. The contingencies include the preparation and commitment to a commercial development plan. ERCE's estimates of the unrisked oil Contingent Resources in the Waddock Cross field, both gross and net to UOG, are shown in Table 1.2. ERCE has reviewed UOG's assessment of chance of development and feel 75% is an appropriate estimation.

Table 1.2: Unrisked Oil Contingent Resources of the Waddock Cross Field, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL090	Waddock Cross	Egdon Resources UK Ltd	0.46	1.55	5.30	26.25%	0.12	0.41	1.39	75%

Notes:

1) *"Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field without any economic cut-off being applied.*
2) *"Net Contingent Resources" are UOG's working interest fraction of the gross contingent resources.*
3) *Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the field will be developed or that the volumes reported as Contingent Resources will be recovered.*
4) *The volumes reported here are unrisked in that they have not been multiplied by the chance of development (Pd).*
5) *In accordance with SPE PRMS.*

1.2.1.2. Colter East Discovery (P1918)

Licence P1918 is located offshore southern UK, south of the Wytch Farm oil field and contains the Colter oil discovery. The licence is operated by Corallian and UOG holds a 10% working interest.

The discovery contains oil within the Sherwood Sandstone reservoir. The Colter discovery appears to be segmented by a northwest to southeast trending fault. However, there is uncertainty associated with both the presence and location of this fault at reservoir level and current PrSDM reprocessing of the seismic survey designed to better image the structure at top reservoir may change this interpretation.

Well 98/11-3 penetrates the eastern segment of the discovery (Colter East). The well was tested and flowed 8.5 bbl of oil to surface together with water. Plans to drill an up-dip appraisal well in Q1 2019 are well underway. The operator Corallian has been issued the relevant consents from OPRED, performed a site survey and contracted the Ensco 72 jack-up drilling unit to drill the well. Drilling commenced on 6 February 2019 and is expected to take approximately three weeks to reach a planned total depth of 1,830 meters. ERCE therefore attributes unrisked Contingent Resources (sub-classification Development Pending) to Colter East as shown in Table 1.3. The contingencies include the success of the updip appraisal well and the commitment to, and preparation of a commercial development plan. ERCE has reviewed UOG's assessment of chance of development and feel 75% is an appropriate estimation.

Table 1.3: Unrisked Oil Contingent Resources of Colter East, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL1918	Colter East	Corallian Energy Limited	1.68	4.08	10.12	10.00%	0.17	0.41	1.01	75%

Notes:

1) *Refer to notes under Table 1.2*

1.2.1.3. Crown Discovery (P2366)

Licence P2366 is located offshore UK at the northwest margin of the Witch Ground Graben and contains the Crown oil and gas discovery. The licence is operated by UOG who hold a 95% interest. The remaining 5% is owned by Swift.

Work commitments involve the reprocessing of 40km^2 of 3D seismic data and an associated rock physics study to better delineate the Crown discovery.

Well 15/19-9 penetrates the Crown discovery, a four-way dip closed anticline. The well found an oil rim of thickness 35 to 55 ft underlying a gas cap in the Balmoral reservoir, a deep marine sandstone turbidite. Production of the gas is at detriment to recovery of oil and as such development plans will aim to minimise any gas production. ERCE attributes unrisked oil Contingent Resources (sub-classification Development Unclarified) to Crown as shown in Table 1.4. ERCE has reviewed UOG's assessment of chance of development and is in agreement that 40% is an appropriate estimate.

Table 1.4: Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	40%

Notes:

1) Refer to notes under Table 1.2

1.2.2. Prospective Resources

1.2.2.1. Broadmayne Prospect (PL090)

The PL090 partnership is maturing prospectivity within the greater licence area, and identifies a number of undrilled exploration prospects and leads. The Triassic Sherwood Sandstone, the main producing reservoir at Wytch Farm to the east, is the primary target. ERCE has independently estimated oil Prospective Resources and Geological Chance of Success for the Broadmayne prospect, which is currently the most mature. Part of the Broadmayne structure is mapped as extending outside licence PL090. Reprocessing of the 3D seismic survey covering the Broadmayne prospect has recently been completed and preliminary interpretation supports the overall trapping mechanism and lateral extent of the historical mapping. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report.

ERCE's estimates of the gross unrisked oil Prospective Resources in Broadmayne and the net unrisked and risked Prospective Resources attributable to UOG based on the mapped area of the prospect in Licence PL090 are shown in Table 1.5.

Table 1.5: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Broadmayne Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Broadmayne	Egdon Resources UK Limited	5.00	11.10	24.50	13.40	1.50	3.30	7.40	4.00	18.95%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimates to fall within the PL090 block boundary (50%).*

Notes:

1) *Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are likely to become drillable targets.*
2) *"Gross Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from an accumulation*
3) *"Net Unrisked Prospective Resources" are UOG's working interest fraction of the gross resources*
4) *"Net Risked Prospective Resources" are UOG's working interest fraction of the gross resources multiplied by the geological chance of success (COS).*
5) *The geological chance of success (COS) is an estimate of the probability that drilling the prospect would result in a discovery as defined under SPE PRMS.*
6) *Prospective Resources reported here are "risked" in that the volumes have been multiplied by the COS; they have not been multiplied by the chance of development (Pd).*

1.2.2.2. Colter West Prospect (P1918)

The Colter West prospect is separated from Colter East by a northwest to southeast trending fault. Colter West is penetrated by Well L98/06-M18Z, known as Old Harry, which was drilled in 2000 to the west of Well 98/11-3. Old Harry appeared to encounter some thin hydrocarbon-bearing sands in the Sherwood (presumed to be oil bearing), based on log responses. No tests were undertaken. ERCE therefore assigns Prospective Resources to Colter West updip of the Old Harry well. ERCE's estimates of the gross unrisked oil Prospective Resources and Geological Chance of Success for Colter West and the net unrisked and risked Prospective Resources attributable to UOG in the P1918 Licence are shown in Table 1.6. ERCE has reviewed UOG's assessment and believe this to be a fair appraisal.

Table 1.6: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Colter Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter West	Corallian Energy Limited	15	38	95	49	4	11	29	15	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Colter West	Corallian Energy Limited	0.43	1.13	2.87	1.47	50%	0.22	0.56	1.44	0.74

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the P1918 Licence (10.00%).*

Notes:

1) *Refer to notes under Table 1.5*

1.2.2.3. Acle Prospect (P2264)

Licence P2264 is located offshore UK in the Southern North Sea and contains the Acle prospect, which comprises a tilted fault block. The Acle prospect targets the Permian Rotliegend, and the structure is in close proximity to a number of producing gas-fields. ERCE's estimates of the gross unrisked gas Prospective Resources and the net unrisked and risked Prospective Resources attributable to UOG in the P2264 Licence are shown in Table 1.7.

Table 1.7: GIIP, Gas Prospective Resources and Geological Chance of Success for the Acle Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	GIIP (Bcf)				Gross Unrisked Prospective Resources (Bcf)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Acle	Swift Exploration Limited	57	132	301	163	42	99	226	122	24%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (Bcf)**				**COS**	**Net Risked Prospective Resources (Bcf)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Acle	Swift Exploration Limited	10	24	54	29	43%	4.4	10.2	23.3	12.6

- **Net Unrisked and Risked Prospective Resources assume execution of a Farm-in Agreement to Licence P2264 (24.00%)*

Notes:

1) Refer to notes under Table 1.5

1.2.2.4. Colibri Prospect (Walton-Morant)

The Walton Morant licence block, offshore Jamaica, contains a number of prospects and leads. The primary target reservoir is the Middle Eocene sands of the Guy's Hill formation. ERCE has independently estimated Prospective Resources for the Colibri prospect, which is the most mature in the current portfolio. ERCE's estimates of the gross unrisked oil Prospective Resources for Colibri and the net unrisked and risked Prospective Resources attributable to UOG in the Walton Morant Licence are shown in Table 1.8.

Table 1.8: STOIIP, Oil Prospective Resources and Geological Chance of Success for the Colibri Prospect, Gross and Net UOG

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colibri	Tullow Jamaica Ltd	129	498	1791	805	30	128	513	229	20%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Colibri	Tullow Jamaica Ltd	6	26	103	46	20%	1.19	5.00	20.08	8.97

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the Walton-Morant Licence (20.00%)*

Notes:

1) Refer to notes under Table 1.5

1.2.3. Leads

1.2.3.1. PL090

Preliminary mapping of seismic data has defined a number of other potential structural traps at Sherwood Sandstone level that are partially or wholly within licence PL090. These include the Casterbridge, Owermoigne East and West and Winfrith structures. UOG's evaluation of these leads is still at an early stage and further technical work is required to mature these to drillable prospects.

1.2.3.2. Walton-Morant

The Walton-Morant licence covers an area of 32,065 km^2 and Tullow has defined a number of potential structural and stratigraphic traps in both the Walton and Morant basins. Interpretation of the recently acquired 3D data has high graded Oriole and Tody to be the most attractive. The viability of these will be further assessed based on the results of drilling the Colibri prospect.

2. Contingent Resources

2.1. Waddock Cross Field (PL090)

2.1.1. Introduction

The Waddock Cross field is located in licence PL090 and is operated by Egdon Resources UK Limited ("Egdon"). The licence is located within the Wessex Basin in the county of Dorset, onshore UK (Figure 2.1).

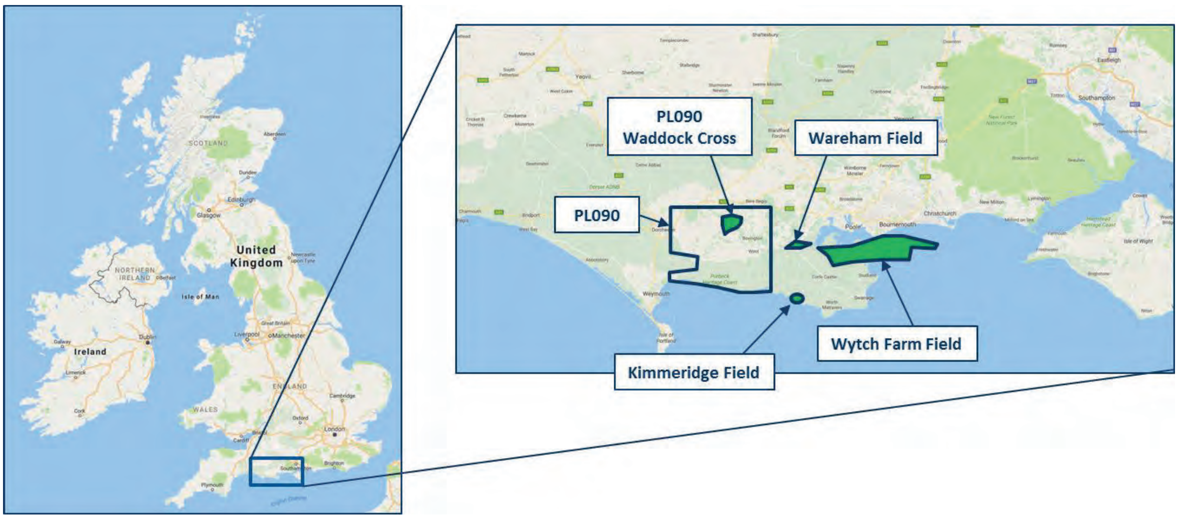

Figure 2.1: PL090 Licence Location and Neighbouring Oil Fields (Source UOG)

Waddock Cross is located in rural farmland close to woodlands approximately 11.5 km east of Dorchester and 21.6 km west of Poole. The Grid Reference (UK National Grid) for the site is SY805912. When the field was previously in production in 2013/14, oil was exported via road tanker to Holybourne Oil Terminal in Hampshire, power was supplied via mains electricity, and water was reinjected through the WX-2 well.

Neighbouring oil fields include the Wareham and Wytch Farm oil fields. The Wytch Farm field produces oil predominantly from the Triassic Sherwood Sandstone reservoirs, with subordinate production from the younger Jurassic Bridport Sandstone reservoir. The Wareham field also produces oil from the Bridport Sandstone reservoir.

The Waddock Cross field was discovered by British Gas in 1982 with Well WX-1. The primary objective was the Triassic Sherwood Sandstone, which did not contain hydrocarbons. A 22 m thick oil column (oil gravity of 29° API) was encountered in the shallower Jurassic Bridport Sandstone at a depth of ca 610 m TVDSS. The oil bearing reservoir can be subdivided into two units; the upper unit Cycle 3 has slightly poorer reservoir qualities than the underlying unit Cycle 2 which possesses better porosity and permeability. Cyclicity within the Bridport Sandstone can be correlated to the Wytch Farm oil field and also to outcrop. An extended well test was conducted in Well WX-1 over a period of 90 days at liquid rates of ~70-80 bbl/d during which the water-cut increased to 80% and the well was plugged and abandoned.

Egdon acquired operatorship in 2003 and drilled Well WX-2 which was completed in January 2004. The well was drilled in close proximity to Well WX-1 and also encountered a 22 m thick oil column.

Several drill stem tests were conducted in Well WX-2. Cycle 2 and Cycle 3 were tested both independently, and as a commingled production stream. Cycle 2 and Cycle 3 both independently produced oil, however in all cases the stabilised water-cut was at ~90% or above.

After the acquisition and interpretation of a 3D seismic survey over the area, Well WX-3 was designed and drilled as a horizontal appraisal well in 2005. The Bridport Sandstone was encountered approximately 9 m deep to prognosis and the well was completed in Cycle 3 to stay above the oil water contact and did not penetrate the better-quality Cycle 2 as originally intended.

Two extended well tests were conducted in Well WX-3 in 2005/6 which flowed oil rates of 53 stb/d and 40 stb/d respectively, both at a water-cut of ~90% over a total period of 22 days. A final extended well test was conducted in 2011-12 with intermittent periods of production from both Wells WX-2 and WX-3. The average combined oil rate was 17 stb/d at a water-cut of 95% over a total period of 59 days. In December 2011, a diesel squeeze was carried out in Well WX-3. However, the workover impacted the oil rate negatively (WX-3 water-cut increased from 90% to 99.5%) and the well test was abandoned shortly after.

The field was put into production through WX-2 in 2013 however results were disappointing. The average oil rate was ~8 stb/d at a water-cut of ~98% and the field was shut-in in 2014.

In late 2014, a workover was carried out with the objective of identifying and isolating the higher water-cut zone in Well WX-3. However, having isolated what was believed to be the higher water-cut zone, it was not possible to establish flow again in Well WX-3.

Egdon advises that there are currently two suspended wells on site, along with two fluid storage tanks that are contained with a purpose-built masonry bund. Other facilities still on site are the concrete tanker loading bay; anti-vandal site office and separate anti-vandal toilet block; constructed mains electricity sub-housing and surface water interceptor. The site area is 1.6ha which includes the access track from the road and is fenced with livestock post and wire fencing. Access from the road is secured with two palisade fence gates, and security is maintained by daily mobile patrol visits. End of life abandonment would require the recovery of the two downhole completions (one is a dual completion used for reinjection), abandonment and capping of the two wells, removal of existing facilities, and restoration using the existing sub soil and topsoil bunds. ERCE has reviewed the activities required to return the site to its former state and believe that the gross costs could range between a low and high estimate of £230,000 and £330,000 respectively.

There is no committed work programme on Waddock Cross. However, reservoir modelling and well costing is being undertaken ahead of well-planning.

2.1.2. Regional and Reservoir Geology

The Wessex Basin comprises four north-dipping half graben sub-basins, with northerly thickening sediments originally controlled by south dipping normal faults. The basin has undergone later tectonism and inversion as a result of (Tertiary) Alpine compression. It is believed that this inversion led to the breaching of a number of hydrocarbon bearing traps.

The stratigraphy of the Wessex Basin is summarised in Figure 2.2. Permian red bed strata containing mudstones, sandstones and basal breccias unconformably overly the deformed Carboniferous-Devonian Basement. The Triassic sediments are comprised of further red bed strata, sandstones, mudstones and conglomerates with halite and mudstone development in the upper part, which provides an intraformational seal. The Sherwood Sandstone was deposited at this time. The overlying Jurassic is formed of an alternating mudstone and carbonate sequence, and contains a number of potential source rock intervals, including the Kimmeridgian and Oxfordian shales. However, much of the oil that has migrated through the basin is sourced from the earlier Liassic shales, with a kitchen area centred to the south of the Wytch Farm field.

Sandstones, including the Bridport Sandstone, are developed in the Lower Jurassic section as the basin filled. Early Cretaceous strata are only preserved in a few basinal areas, with the area eventually covered by mid-late Cretaceous Chalk and Tertiary sediments. Alpine inversion has resulted in later structural modification, and the erosion of Tertiary and Upper Cretaceous strata over the area.

The Lower Jurassic Bridport Sandstone consists of very fine to medium grained shallow marine sandstones varying in thickness from 60 to 130 m. Reservoir quality is variable, with permeability in the range of 0.1 – 400 md, and net to gross ratio varying between 15 to 80%. The sandstones contain tightly cemented calcareous layers which form vertical permeability barriers. The thickly developed mudstones of the Middle Jurassic Fullers Earth Formation provide the top seal for the Bridport Sandstone reservoir.

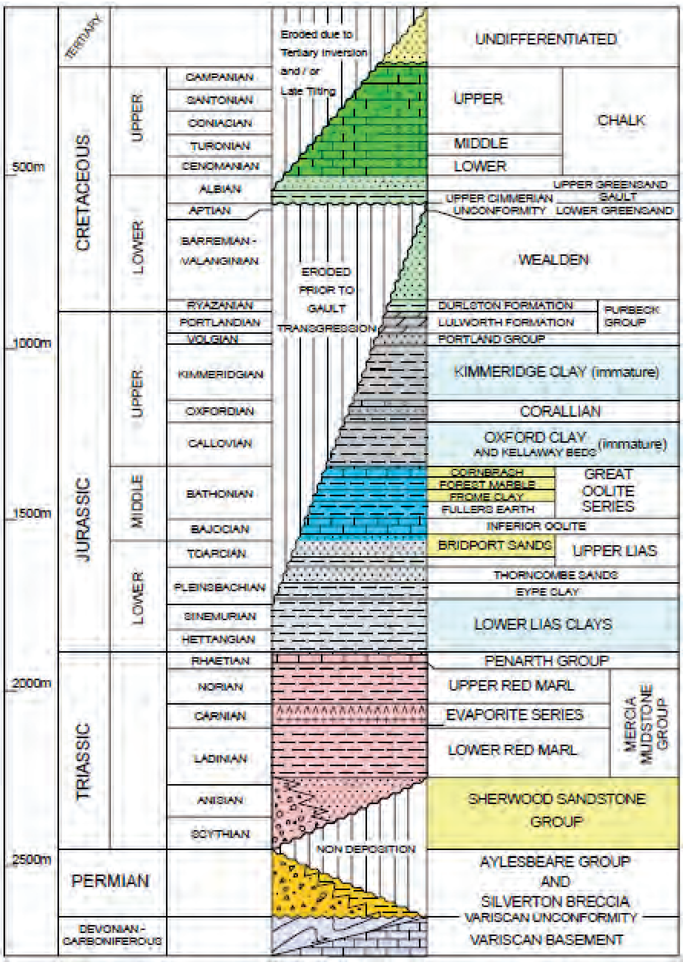

Figure 2.2: Stratigraphic Position of the Principal Source Rocks and Reservoirs of the Wessex Basin (source DTI).

2.1.3. Seismic Data and Structure

A further round of reprocessing has recently been completed which focused on addressing the apparent near surface statics issues. The reprocessing has resulted in both PSTM (time domain) and PSDM (depth domain) seismic volumes.

ERCE has assessed both the PSTM and PSDM 3D seismic data and acknowledges an improvement in imaging associated with the PSTM volume.

A representative seismic section from the PSTM volume across the Waddock Cross field is shown in Figure 2.3.

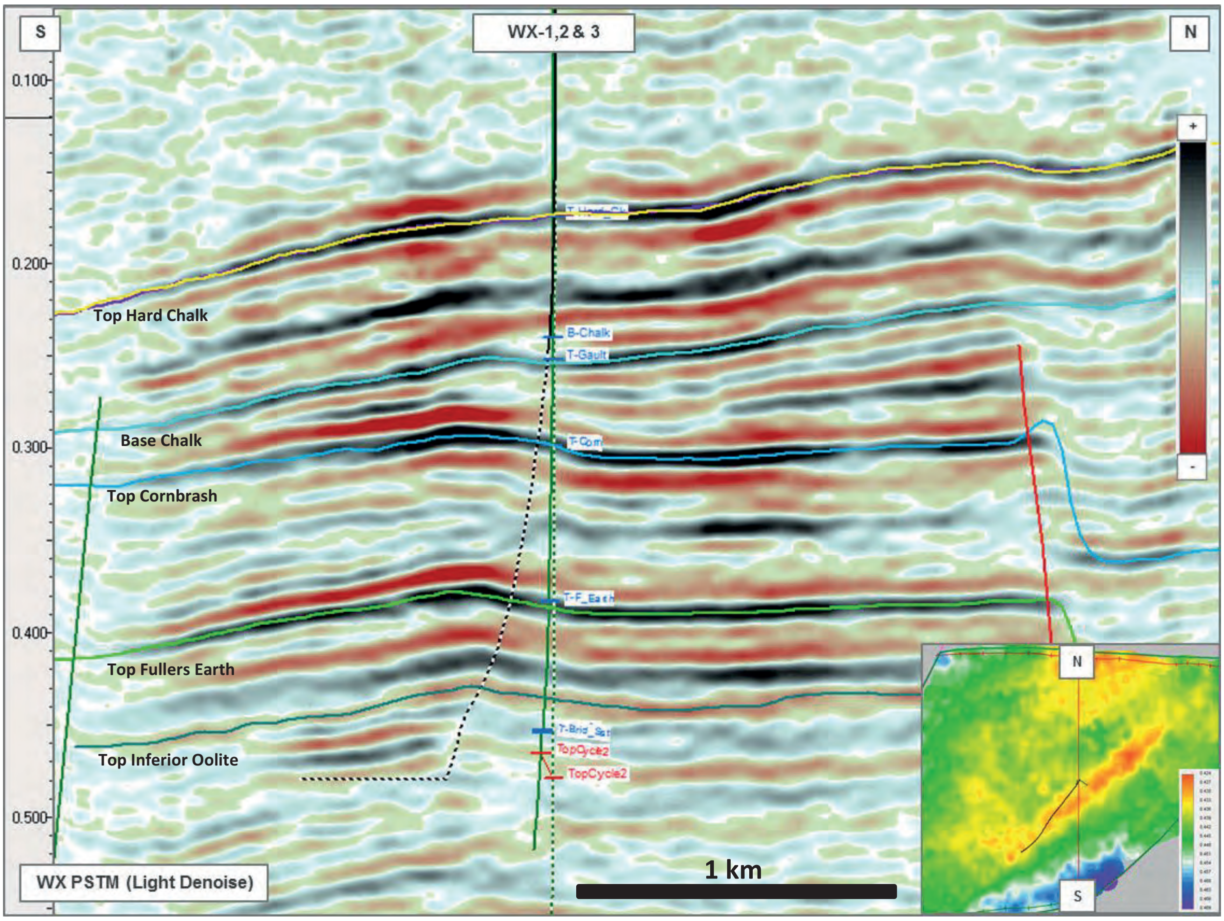

Figure 2.3: N-S Seismic Line Through the Waddock Cross Field

The field is defined by a three-way closure, fault sealed to the north and dip closed to the south, east and west.

2.1.4. Overburden Velocities and Depth Conversion

Overburden geology is complex above the Waddock Cross field, and structural relief is sensitive to depth conversion.

ERCE has assessed all available velocity data and generated independent depth conversion models to explore structural and volumetric uncertainty for the Waddock Cross field. ERCE's best technical case velocity model and the range of velocities explored through multi-realisation modelling is illustrated by Figure 2.4. This plot displays both sonic log velocities from Wells WX-1 and -2 and Well Wareham-3, derived best technical case velocity functions (green lines) and the range of velocities (dashed red lines) explored through multi-realisation modelling. The sonic log from Well Wareham-3 has been shifted to tie at Base Chalk for comparison purposes.

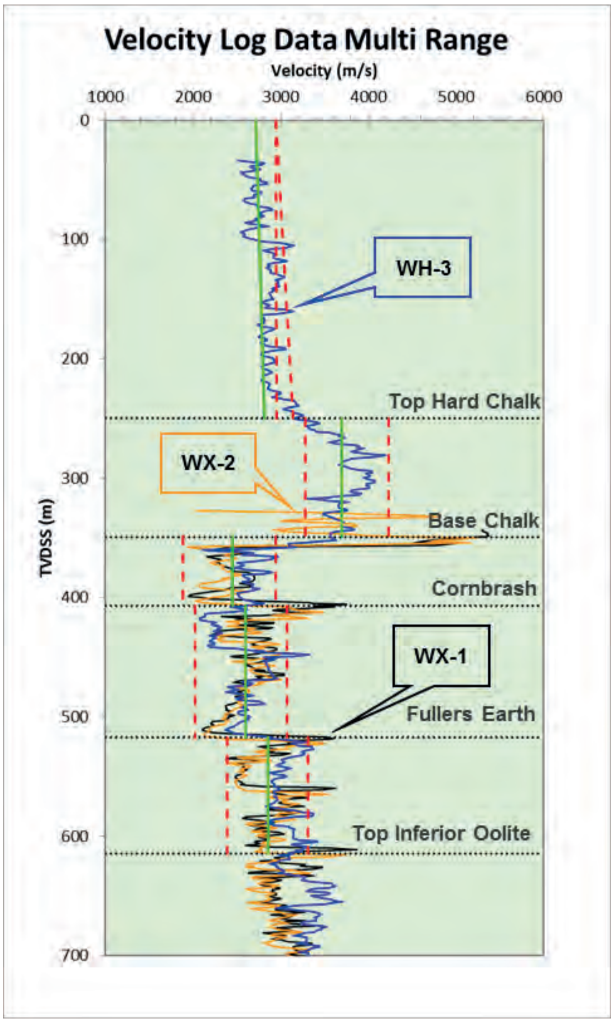

Figure 2.4: Log Velocity Plot - Waddock Cross Velocity Model
(Waddock Cross-1, 2 & Wareham-3)

2.1.5. Petrophysical Review

A petrophysical review of the Waddock Cross wells and Wareham Well C3WP was carried out by PGL in 2006 (the PGL Report). ERCE has carried out an audit of this interpretation and agrees with the results. We therefore adopt this petrophysical analysis as our basis for the evaluation of the Waddock Cross Bridport Sandstone reservoir.

Figure 2.5 presents CPIs of Wells WX-1 and WX-2 from the PGL Report. Cycle 3 is oil bearing in both wells, and an oil water contact (OWC) is encountered in Cycle 2 in both wells at 638.5 m TVDSS. Cycle 2 has better reservoir quality than Cycle 3, with higher net to gross ratios and slightly higher porosity (29% compared to 26%). Water saturation is high in both reservoirs, due to the proximity of the OWC.

Figure 2.6 presents a CPI of horizontal Well WX-3. This well was drilled approximately 10 metres above the OWC. The CPI shows that high water saturations generally greater than 60% are encountered throughout the horizontal section.

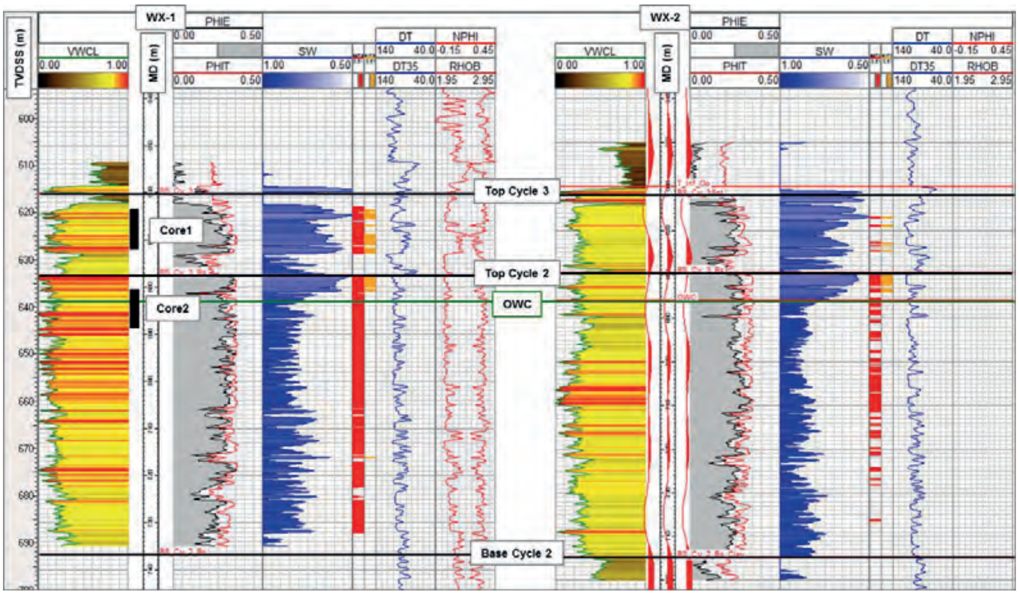

Figure 2.5: CPI Images of Wells WX-1 and WX-2
(Source PGL Report, 2006)

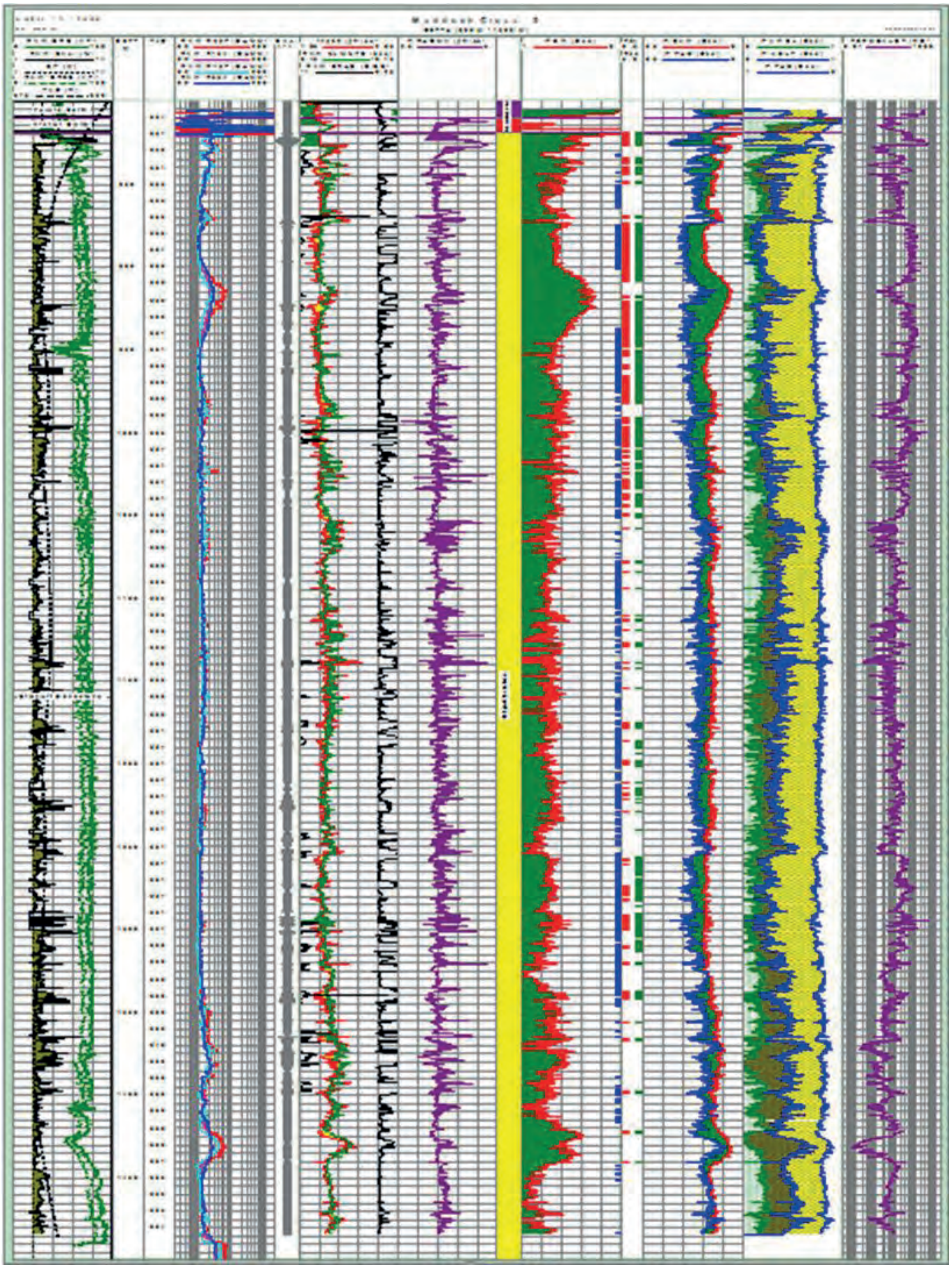

Figure 2.6: CPI Image of Well WX-3
(Source PGL Report, 2006)

2.1.6. Fluid Analysis

Downhole reservoir fluid samples were not made available for review. Reservoir fluid properties have been estimated using surface fluid samples, gas-oil ratio from production tests and standard engineering correlations. Surface oil sample density was measured at 29 °API and it is expected that reservoir fluid has a moderately high viscosity and a formation volume factor close to one.

2.1.7. Well Test Review

The field was discovered by Well WX-1 in 1982 which encountered oil in the Bridport Sandstone. An extended well test was conducted over a period of 90 days however the well was plugged and abandoned due to low oil rates (<10 stb/d) and a high water-cut (~70-80%).

Appraisal Well WX-2 was drilled in 2004 at an offset of 120 m from the discovery well WX-1 and completed in the Bridport Sandstone. Several drill stem tests ("DSTs") were conducted on the WX-2 well. The first DST was over a two metre perforated intervals in Cycle 2 and produced oil at 40 stb/d with a water-cut of ~90% over a 24 hour period. The second test was carried out over a 13 metre perforated interval in Cycle 3 and flowed at an oil rate of 60 stb/d with a water-cut of ~95% over a 30 hour period. A further two DSTs were carried out in Well WX-2 later in 2004 which again flowed at high water-cuts.

In December 2005, horizontal development Well WX-3 was drilled. The well was intended to target Cycle 2 however the reservoir came in nine metres deep to prognosis and the well was instead completed in Cycle 3. The total horizontal section was 690 m. Two extended well tests were conducted in WX-3 in 2005/6 which flowed oil rates of 53 stb/d and 40 stb/d respectively, both at a water-cut of ~90% over a total period of 22 days.

Another extended well test was conducted in 2011-12 with intermittent periods of production from both Wells WX-2 and WX-3. The average combined oil rate was 17 stb/d at a water-cut of 95% over a total period of 59 days. In December 2011, a diesel squeeze was carried out in Well WX-3. However, the workover impacted the oil rate negatively (WX-3 water-cut increased from 90% to 99.5%) and the well test was abandoned shortly after.

The field was put into production through WX-2 in 2013 however results were disappointing. The average oil rate was ~8 stb/d at a water-cut of ~98% and the field was shut-in in 2014.

In late 2014, a workover was carried out with the objective of identifying and isolating the higher water-cut zone in Well WX-3. However, having isolated what was believed to be the higher water-cut zone, it was not possible to establish flow again in Well WX-3.

All well tests conducted in the field have been characterised by high water-cuts. Water-cut development is exacerbated by the relatively high viscosity of the oil. All wells to date have been completed with relatively little offset from the oil water contact and hence have encountered high water saturations. The proposed development plan therefore intends to target areas of the discovery with greater relief where lower water saturations may lead to oil production with less associated water.

2.1.8. Hydrocarbons Initially In Place

ERCE uses probabilistic methods to estimate hydrocarbons in place for the Waddock Cross field. Firstly, we develop a mid case gross-rock volume, using our best technical estimate depth conversion (Section 2.1.4), and an OWC at 638.5 m TVDSS. Top Bridport Sandstone is derived by adding well based isopachs to the overlying top Inferior Oolite – the seismic marker closest to the Bridport Sandstone.

We then perturb velocity model structure and seismic pick uncertainty to generate low and high case estimates of gross rock volume (GRV).

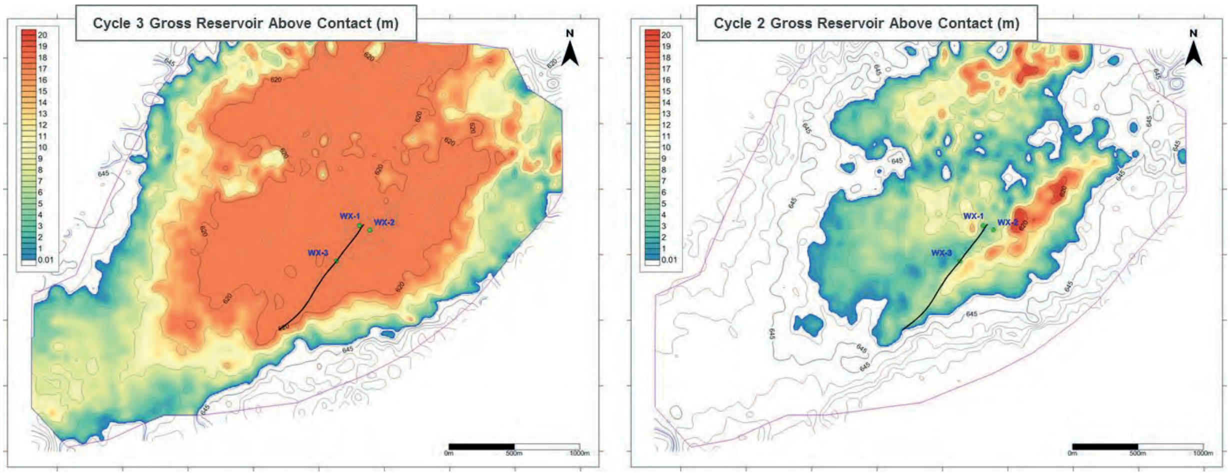

Figure 2.7: Gross Reservoir Thickness Above OWC – Mid Case

(Grey contours represent depth to top reservoir TVDss, blue contour highlights contact depth and the colourfill represents the gross reservoir thickness above contact).

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the field where a shallower structure has been interpreted. A summary of input parameters used in our calculation of stock tank oil initially in place (STOIIP) is presented in Table 2.1.

Table 2.1: Input Parameters – Waddock Cross

Block	Field	Reservoir	GRV (MMm3)			NTG (frac)			Porosity (frac)		
			Low	Best	High	Low	Best	High	Low	Best	High
PL090	Waddock Cross	Cycle3	84	98	114	0.21	0.33	0.47	0.23	0.26	0.28
		Cycle2	11	20	40	0.51	0.63	0.74	0.26	0.29	0.31

Block	Field	Reservoir	HC Saturation (frac)			Bo (rb/stb)		
			Low	Best	High	Low	Best	High
PL090	Waddock Cross	Cycle3	0.4	0.48	0.55	1.01	1.02	1.03
		Cycle2	0.4	0.48	0.55	1.01	1.02	1.03

The results of our STOIIP estimates, separated as Cycle 2 and Cycle 3, are presented in Table 2.2.

Table 2.2: Waddock Cross STOIIP

Block/ Concession	Operator/ Administrator	Field	Reservoir	STOIIP (MMstb)		
				Low	Best	High
PL090	Egdon Resources UK Ltd	Waddock Cross	Cycle3	13.4	20.6	31.7
			Cycle2	3.4	7.9	18.6
			-	**16.8**	**28.5**	**50.3**

2.1.9. Recovery Factor and Oil Contingent Resources

The partners are reviewing the revised interpretation to determine the viability and optimal location to drill a new well.

Reservoir simulation modelling was undertaken by Egdon prior to the drilling of Well WX-3. Our estimates of recovery factor have been guided by the results of this simulation modelling. We assume that two wells with horizontal sections of some 1000 m each will be drilled in structurally shallow areas of the field, allowing a greater offset from the oil water contact. We are of the view that if the reservoir is encountered deeper than prognosis, reflecting the Low case mapping, then a low recovery factor is likely to prevail. In a similar manner, if the reservoir is encountered higher than encountered in the current wells, a higher recovery factor is likely. We have therefore applied recovery factor ranges deterministically to our STOIIP estimates. We have assigned a higher recovery factor range to Cycle 2 to reflect the higher reservoir quality.

ERCE has reviewed UOG's assessment of chance of development and feel 75% is an appropriate estimation.

Table 2.3 presents our estimates of STOIIP, recovery factor and oil Contingent Resources (sub-classification Development Pending).

Table 2.3: Waddock Cross STOIIP, Recovery Factor and Oil Contingent Resources

Block / Concession	Field	Operator / Administrator	Reservoir	STOIIP (MMstb)			Recovery Factor (%)			Gross Contingent Resources (MMstb)		
				Low	Best	High	Low	Best	High	1C	2C	3C
PL090	Waddock Cross	Egdon Resources UK Ltd	Cycle 3	14.1	23.8	36.8	1.5%	2.1%	3.0%	0.21	0.50	1.10
			Cycle 2	5.1	10.5	21.0	5.0%	10.0%	20.0%	0.25	1.05	4.20
			Total	**19.2**	**34.3**	**57.8**	**-**	**-**	**-**	**0.46**	**1.55**	**5.30**

Notes:

1) *Refer to notes under Table 1.2*
2) *Waddock Cross carries a 75% chance of development.*

2.2. Colter East Discovery (P1918)

2.2.1. Introduction

The Colter discovery is located in licence P1918 and is operated by Corallian. The licence is located offshore southern UK, south of Wytch Farm oil field (Figure 2.8).

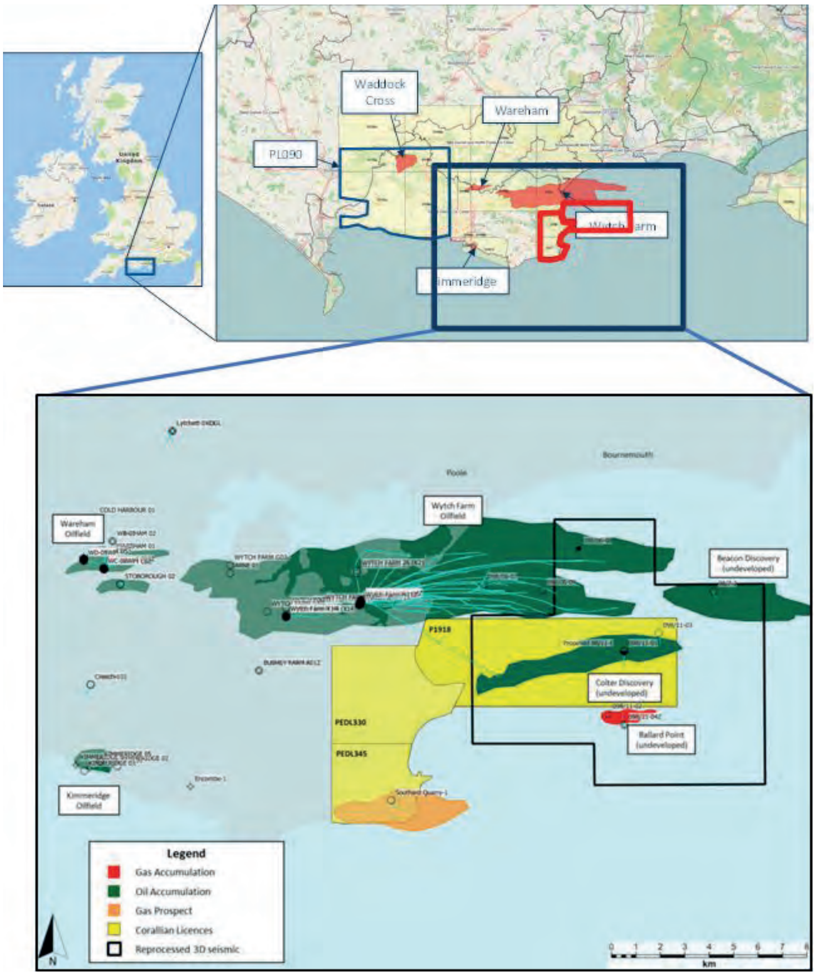

Figure 2.8: Colter Discovery Location Map
(Source: United Oil & Gas Summary Presentation)

There have been three wells drilled at Colter. Two of the wells, drilled in the 1980s, sought to test fault structures to the south of a newly discovered Wytch Farm. Well 98/11-1 was drilled in 1983 to test fault seal at Bridport and Sherwood sandstone horizons, and encountered what was considered at the time to be sub-economic oil in a rotated fault block down-thrown to the south of the Colter discovery.

In 1986, Colter was discovered by Well 98/11-3. The well encountered a 10.5m section of the Sherwood Sandstone reservoir with oil saturations from logs up to 60%, underlain by water-bearing Sherwood Sandstone.

A DST was performed on Well 98/11-3, with 8.5 stb of oil produced at surface out of 109 bbl total fluid production, including water. The flow rate declined rapidly on test due to water ingress and lack of gas to lift the liquids, and it is considered that the tested interval straddled the transition zone. An oil-water contact is indicated on logs at 1740 mTVDss. Average porosity is 18% in the pay interval and overall the reservoir quality is very similar to Wytch Farm. Although considered a sub-economic oil discovery at the time, more recent seismic and interpretations have suggested up-dip potential.

The Old Harry extended reach exploration well was drilled in 2000 from an onshore Wytch Farm pad, to the west of Well 98/11-3. Log analysis indicates the presence of thin potentially hydrocarbon-bearing sands near the top of the Sherwood reservoir, underlain by water. No tests were undertaken. Reservoir quality at the top of the Sherwood Sandstone is poor, and a possible contact is identified at c. 1750 mTVDss. Below the top 18 m of poor quality reservoir, a further 105 m gross reservoir was encountered, with 73% net to gross, and average porosity of 17%. This section represents good quality Sherwood reservoir similar to Wytch Farm and Well 98/11-3.

These wells are shown on the top reservoir depth structure map in Figure 2.9.

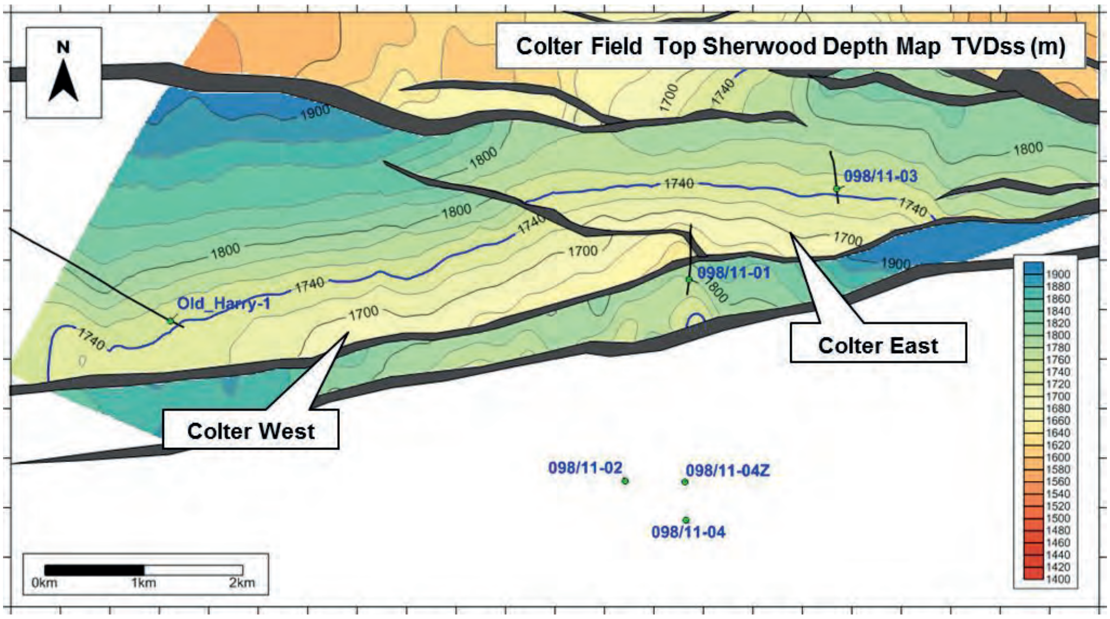

Figure 2.9: Well Locations and Top Sherwood sst Depth Map (mTVDss)

The Colter structure appears to be segmented by a northwest to southeast trending fault, dividing the discovery into Colter East and West. Given that Well 98/11-3 (Colter East) flowed oil, and no tests were carried out coupled with the uncertain log analysis at Well Old Harry (Colter West), ERCE has attributed Contingent Resources to Colter East and Prospective Resources to Colter West. The contingencies associated with Colter East include the success of the updip appraisal well and the commitment to, and preparation of a commercial development plan. There is uncertainty on both the presence and location of this fault at the reservoir level. This position may be subject to change based on the results of the seismic reprocessing that is currently in progress.

The Colter East discovery and associated Contingent Resources are discussed in this section, and the Colter West prospect is discussed in Section 3.1.3.

The well which was spudded on 6 February 2019 will satisfy the current work commitments. The well's objective is to appraise the Colter discovery made by Well 98/11-3 in the Sherwood Sandstone.

2.2.2. Regional and Reservoir Geology

The Colter discovery also sits within the Wessex Basin, and so shares a geological history with Waddock Cross, as described in Section 2.1.2 and Figure 2.2.

The Sherwood sandstone is the principal reservoir for the Colter accumulation, deposited in the Triassic in a fluvial environment, and sealed by Jurassic Mercia mudstones. The Bridport sands, deposited in a shallow marine setting in the Lower Jurassic are a potential secondary target at Colter.

The Colter accumulation is trapped within a tilted fault block, analogous to Wytch Farm.

2.2.3. Seismic Data and Structure

The interpretation of the Top Sherwood event is challenging due to structural complexity and poor seismic signal below fast and steeply dipping chalk sediments at the surface. The Top Penarth event is therefore used as a proxy for Top Sherwood through application of a well isochron. The structure is mapped as dip closed to the north and fault sealed to the south and west. Reprocessing of the seismic survey was completed in April 2018. However, the resultant seismic image does not alter the existing interpretation, nor the location and uncertainty associated with the bounding faults. Figure 2.10 shows a north to south seismic section over the East Colter discovery.

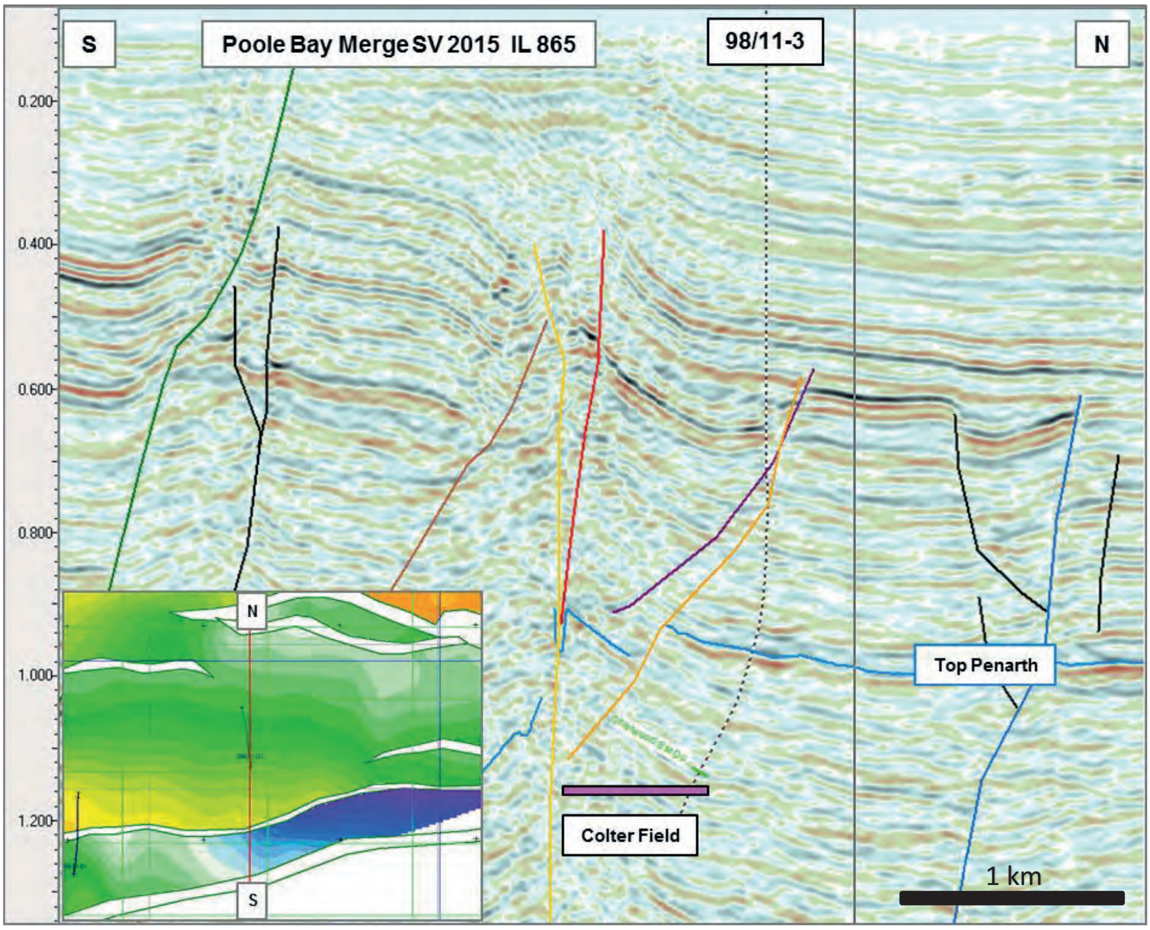

Figure 2.10: S-N Seismic Section Over the East Colter Discovery

ERCE has assessed the operator's seismic interpretation and isochron methodology for the Top Penarth and Top Sherwood respectively over the Colter structure and has adopted it for our volumetric assessment.

2.2.4. Depth Conversion

ERCE has reviewed the various approaches used to depth convert the Top Sherwood event defining the Colter discovery. All methods reveal a velocity trend that increases to the west helping to create dip closed structures. However, given the poor seismic signal and challenging interpretation depth conversion is felt to be a subsidiary control on GRV sensitivity, and ERCE has adopted the depth structure used by UOG to perform further fault sensitivity analysis. A representative depth map is presented in Figure 2.11.

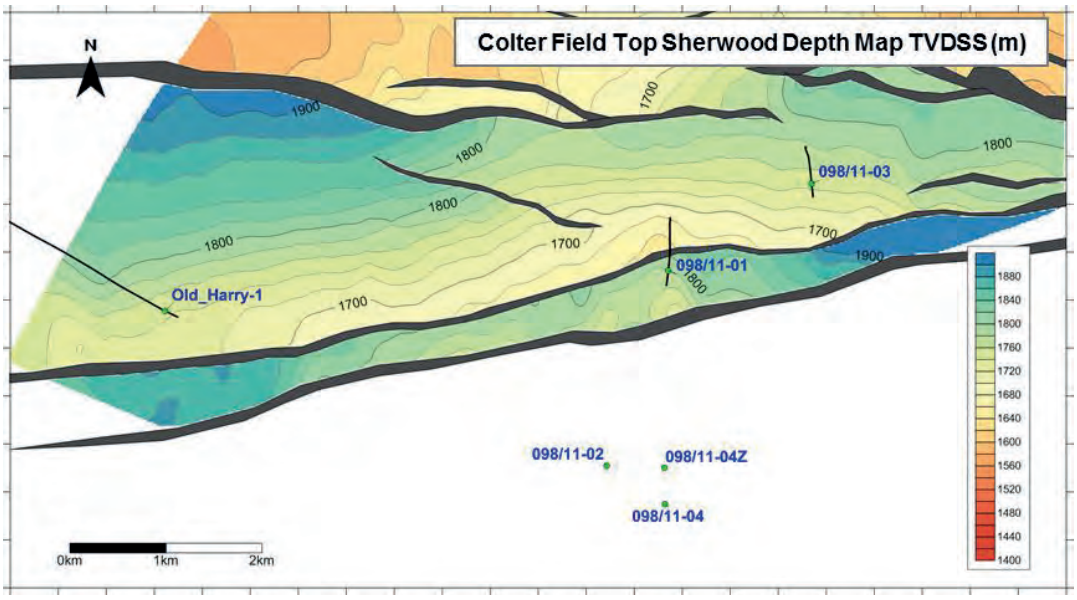

Figure 2.11: Colter Discovery Top Sherwood Depth Map TVDSS (m)

2.2.5. Petrophysical Review

ERCE has carried out an independent petrophysical interpretation for Wells 98/11-1 and 98/11-3.

A CPI for Well 98/11-3 is shown in Figure 2.12. Reservoir quality in the Sherwood is typically good, and with moderate hydrocarbon saturations in the upper Sherwood. An apparent oil water contact (OWC) is encountered at around 5704 ftTVDss (1939 mTVDss). The composite log notes strong florescence in sands and gas shows.

Well 98/11-1, drilled in the small fault block to the south of Well 98/11-3, appears to exhibit similar good quality reservoir properties, but only minor hydrocarbon saturation. Good fluorescence is noted, with bleeding oil observed in core, but no gas shows were observed. A test flowed water. This could indicate a residual oil accumulation.

Although petrophysical interpretations were not provided by the client, ERCE's petrophysical averages show good agreement with the range of petrophysical averages used in UOGs volumetric cases. Given the uncertainty in maximum potential hydrocarbon saturations from these wells, Wytch Farm has been used as a nearby analogue.

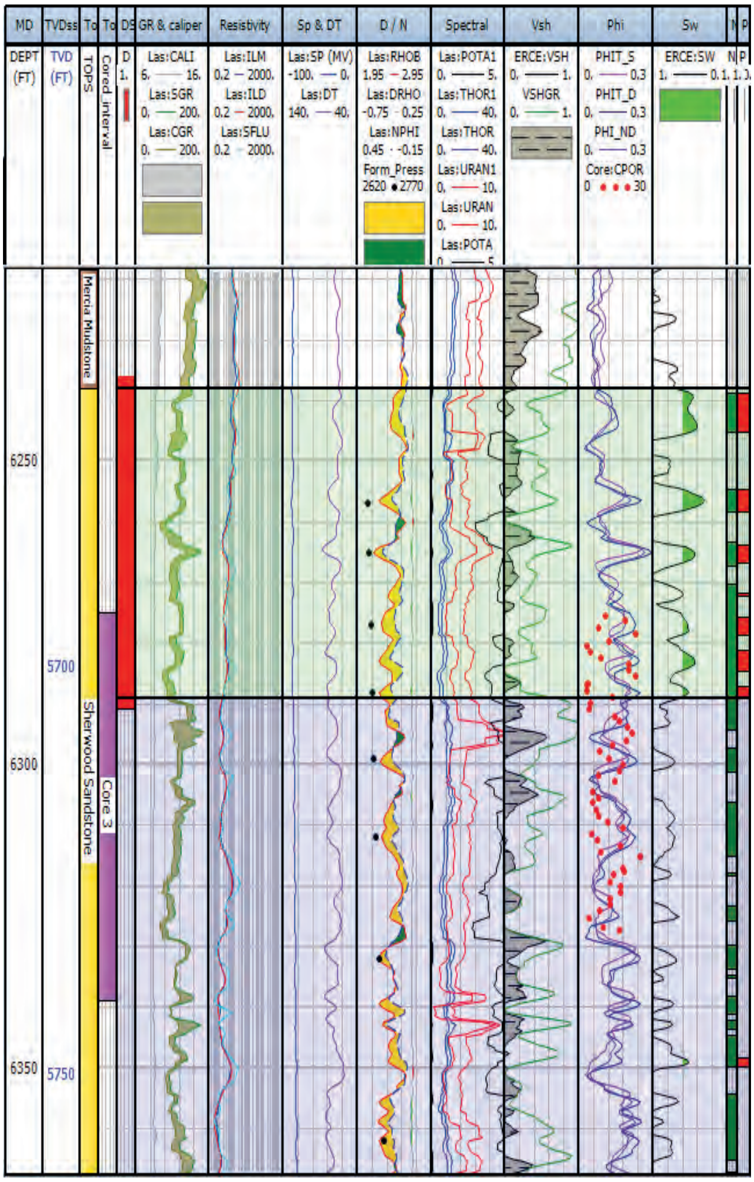

Figure 2.12: CPI for Well 98/11-3

2.2.6. Well Test Review

DSTs were carried out on Wells 98/11-1 and 98/11-3.

The Sherwood interval over which the DST was performed in Well 98/11-3 is shown (in red) on Figure 2.12. The report indicates that 8.5 bbl of oil were flowed to surface, out of 109 bbl total production, which suggests movable oil bearing reservoir, with significant water production. The DST appears to tag the proposed oil water contact which may explain the high water cut. Given the good quality Sherwood Sandstone reservoir encountered, it is therefore reasonable to assume that any area updip of the well that can be mapped with sufficient confidence, i.e. Colter East, should contain Contingent Resources.

The DST performed on Well 98/11-1 flowed water only, again consistent with a minor/residual hydrocarbon accumulation in this fault block, despite similar reservoir quality to Well 98/11-3.

2.2.7. Hydrocarbons Initially In Place and Contingent Resources

ERCE uses probabilistic methods to estimate hydrocarbons in place and Contingent Resources for the Colter East discovery.

The principal volumetric uncertainty at Colter East is the positioning of the main south to east trending fault at the Top Sherwood level, and the northwest to southeast fault which separates Colter East and Colter West. ERCE has therefore explored low and high cases for GRV based on lateral fault positioning and an OWC at 1740 mTVDSS in accordance with the contact observed at Well 98/11-03. Low and high case GRV cases are illustrated in Figure 2.13.

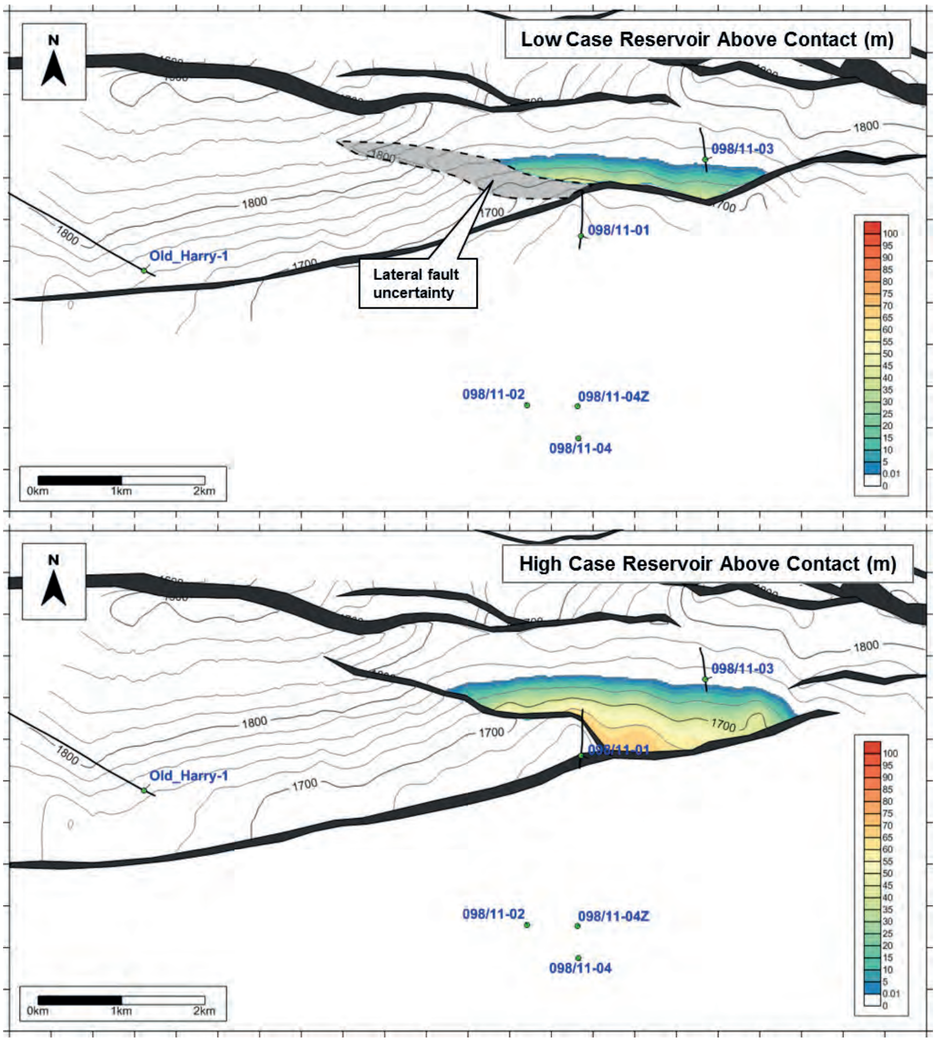

Figure 2.13: Gross Reservoir Thickness Above OWC
(Grey contours represent depth to top reservoir TVDss, the colourfill represents the gross reservoir thickness above contact).

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the structure, based on analogue saturations in the nearby Wytch Farm field. A summary of input parameters used in our calculation of STOIIP is presented in Table 2.4.

Table 2.4: Input Parameters - Colter East

Block	Field	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
P1918	Colter	Sherwood	Oil	16	36	82	0.6	0.7	0.8	0.15	0.18	0.21
Block	**Field**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	Best	High	Low	Best	High	Low	Best	High
P1918	Colter	Sherwood	Oil	0.5	0.6	0.7	1.15	1.2	1.25	0.25	0.30	0.35

Our Gross and Net Contingent Resources (sub-classification Development Pending) estimates are presented in Table 2.5. ERCE has reviewed UOG's assessment of chance of development and feel 75% is an appropriate estimation.

Table 2.5: Unrisked Oil Contingent Resources of Colter East, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
PL1918	Colter East	Corallian Energy Limited	1.68	4.08	10.12	10.00%	0.17	0.41	1.01	75%

Notes:

1) *Refer to notes under Table 1.2*
2) *Colter East carries a 75% chance of development.*

2.3. Crown Discovery (P2366)

2.3.1. Introduction

The Crown discovery is located in Block 15/19, offshore UK. UOG was awarded a 95% interest in the block in August 2018 as part of the UK offshore 30th Licensing Round. The licence is located offshore UK at the northwest margin of the Witch Ground Graben (Figure 2.14).

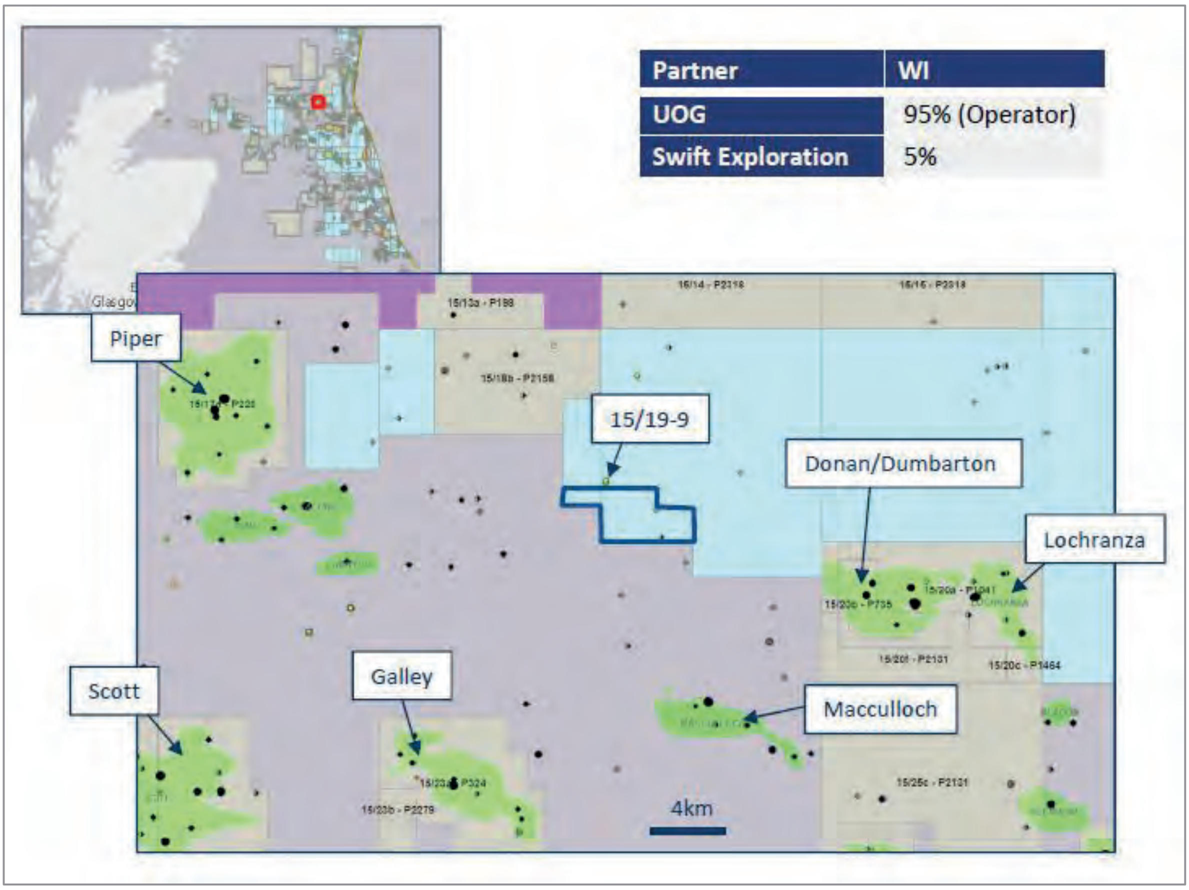

Figure 2.14: Crown Discovery Location Map
(Source: UOG Presentation)

Twelve wells have been drilled in the block. Wells 15/19-1, 2 & 3 were dry holes drilled between through 1974 to 1976, testing tilted fault blocks at Jurassic level. Well 15/19-1 was a dry hole drilled in 1974 by Conoco to evaluate a structural-stratigraphic trap in the Upper Jurassic sandstones approx. 15 miles ESE of the Piper field. Well 15/19-2, drilled in 1974, evaluated a prospective structural closure at Base Tertiary/Top Danian and a structural stratigraphic trap in pre-Upper Cretaceous chalk beds. The Palaeocene sandstones were the primary objective and these were found to be dry. Well 15/19-3 was drilled in 1976 to test the Upper Jurassic Piper sandstones which were found to be absent, but the top of the Lower Palaeocene sands were oil bearing. The well was plugged and abandoned as a dry hole.

A second phase of exploration was undertaken in 1984 to 1986 to test the Jurassic Piper Sands, during which a further two dry holes were drilled (Wells 15/19-4 & 5). In 1993 to 1996 Wells 15/19-6 & 7 to tested the Piper and Palaeocene sands and Well 15/19-6 encountered an oil column in the Piper.

Drilling in 1998 focussed on the Balmoral sand channel play and Wells 15/19-8 and 15/19-9 encountered the Crown oil discovery. Well 15/19-10b was drilled the Stag discovery in 2007, encountering oil in Balmoral sands.

The southern part of the Block 15/19c was awarded to Maersk in 2009 in pursuit of the Balmoral play following its successful redevelopment of the Donan field renamed Dumbarton. Maersk subsequently drilled Wells 15/19c-11 in 2010 and 15/19c-12 in 2014 to test AVO anomalies on the Balmoral channel fairway.

Well 15/19-9 encountered in excess of 200 ft of the Palaeocene Balmoral Sandstone reservoir with an oil column between ~35 to ~55 ft and a gas column of ~30 ft, underlain by water-bearing Balmoral Sandstone. Core was cut and shows favourable reservoir properties with an average porosity of 27% and permeability mostly between 500 mD and 1500 mD. No DSTs were performed. An attempt was made to run a pipe conveyed MDT but this was unsuccessful.

2.3.2. Regional and Reservoir Geology

The Crown discovery is a four-way dip closure located at the northwest margin of the Witch Ground Graben. The Witch Ground Graben and Fladen Spur were a result of extension and associated fault movement during the Late Jurassic. These structural elements had a major influence on the later deposition of deep marine sand rich turbidites sourced from the Scottish mainland and Shetland Platform which form the Palaeocene Balmoral reservoir sands at Crown.

A chronostratigraphic column showing the principal source rocks and reservoir units is shown in Figure 2.15.

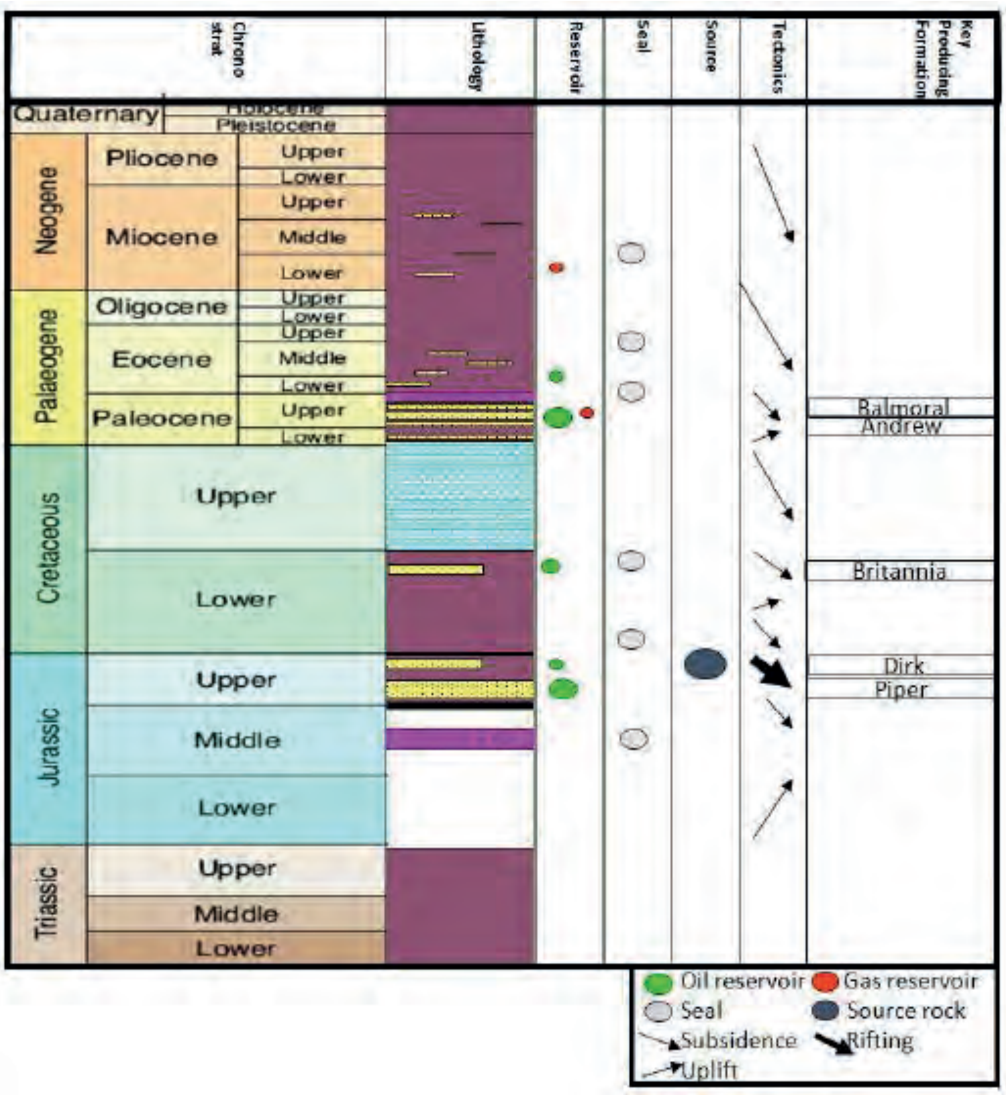

Figure 2.15: Stratigraphic Column, Witch Ground Graben and Fladen Spur.
(Source: United Oil & Gas Summary Presentation)

2.3.3. Seismic Data and Structure

The 3D seismic data over the Crown discovery were released in 1993, are of good quality, and allow for mapping of the key seismic events used to define the velocity model and top reservoir structure (Figure 2.16).

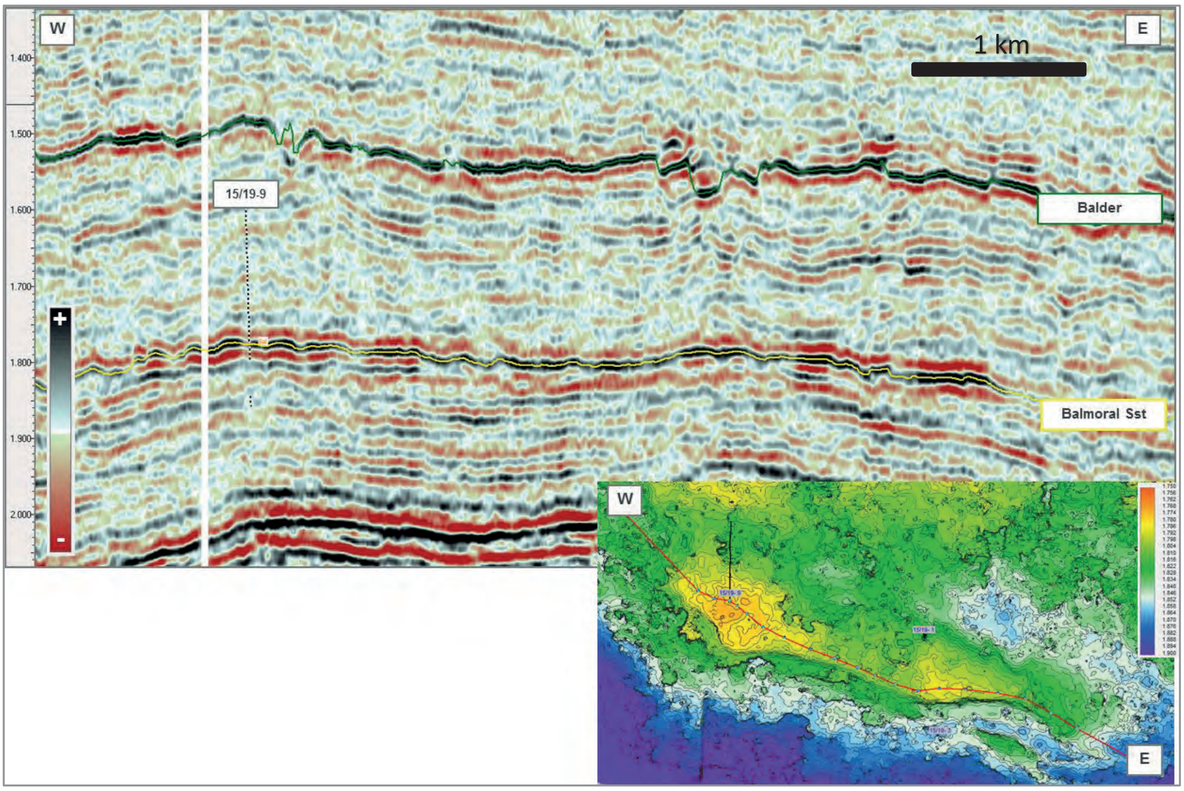

Figure 2.16: Arbitrary seismic line from running West to East along the crest of the Crown discovery

The Top Balmoral Sandstone event can be mapped from Well 15/19b-10 (Stag) which has been tied to the seismic through synthetic matching work, to the Crown discovery (Figure 2.17).

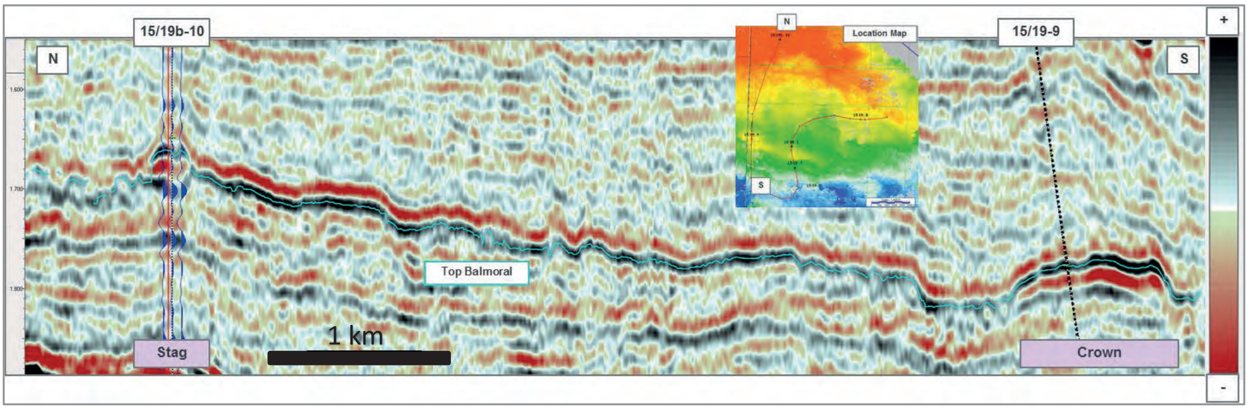

Figure 2.17: Arbitrary seismic line from Stag to Crown

The structure is a well-defined four-way dip closure which is fault bound to the south. ERCE has performed its own independent seismic interpretation for the Top Balder and Top Balmoral and which is in agreement with that provided by the operator.

2.3.4. Depth Conversion

ERCE has assessed all available velocity data and generated independent depth conversion models to explore the structural and volumetric uncertainty of the Crown discovery. ERCE has reviewed both alternative layering schemes and approaches to depth conversion. ERCE has further performed structural sensitivity testing by perturbing the velocity functions through multi-realisation modelling.

Velocity control is provided by sonic log velocities from wells proximal to the field (Figure 2.18) in conjunction with pseudo velocities calculated from formation top depths and associated time grid interpretation. ERCE used optimisation techniques to derive velocity function parameters that minimise residual error between predicted depths and well formation tops.

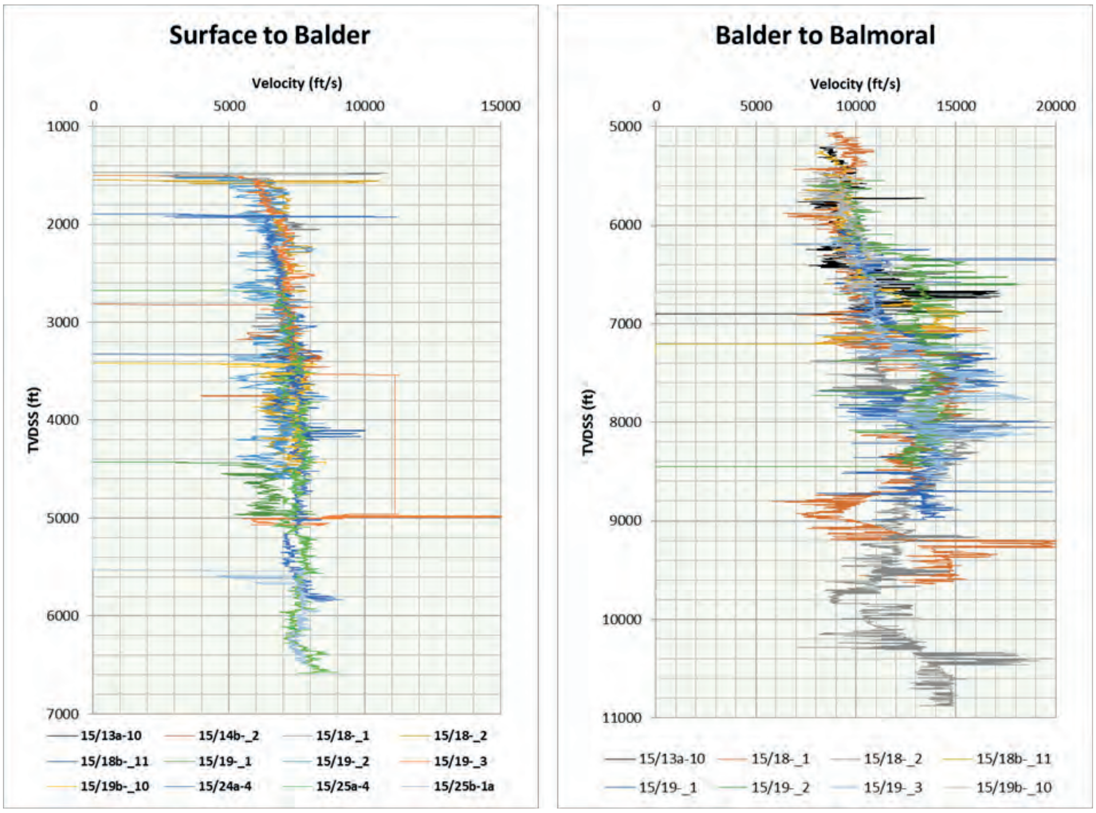

Figure 2.18: Sonic log velocities from proximal well control

2.3.5. Petrophysical Review

ERCE has performed an independent petrophysical review of Well 15/19-9, the Crown discovery well (Figure 2.19). The well is a deviated well with good log coverage and core data. The key uncertainty is water resistivity (Rw), as no water samples have been taken.

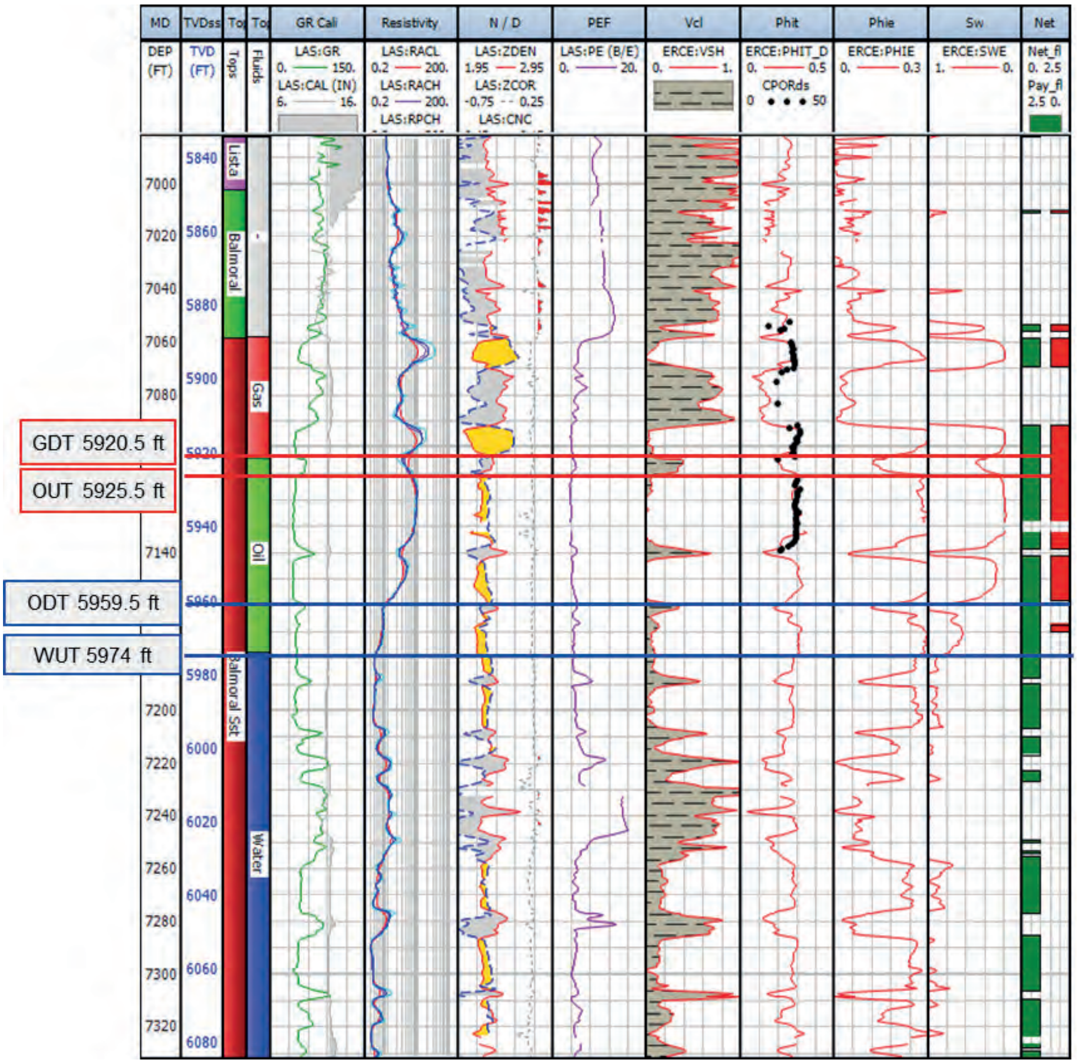

Figure 2.19: CPI Image of Well 15/19-9

The gas oil and oil water contacts as interpreted by ERCE are shown in Figure 2.19. These are also presented in Table 2.6.

Table 2.6: Crown Fluid Contacts

Contacts	TVDss (ft)
GDT	5920.5
OUT	5925.5
ODT	5959.5
WUT	5974.0

Figure 2.20 presents a cross plot of core porosity versus core permeability. The core data show good reservoir quality in the oil and gas leg with porosities of up to 32% and permeability of up to 2 D. There is no obvious difference in reservoir quality between the gas and oil legs.

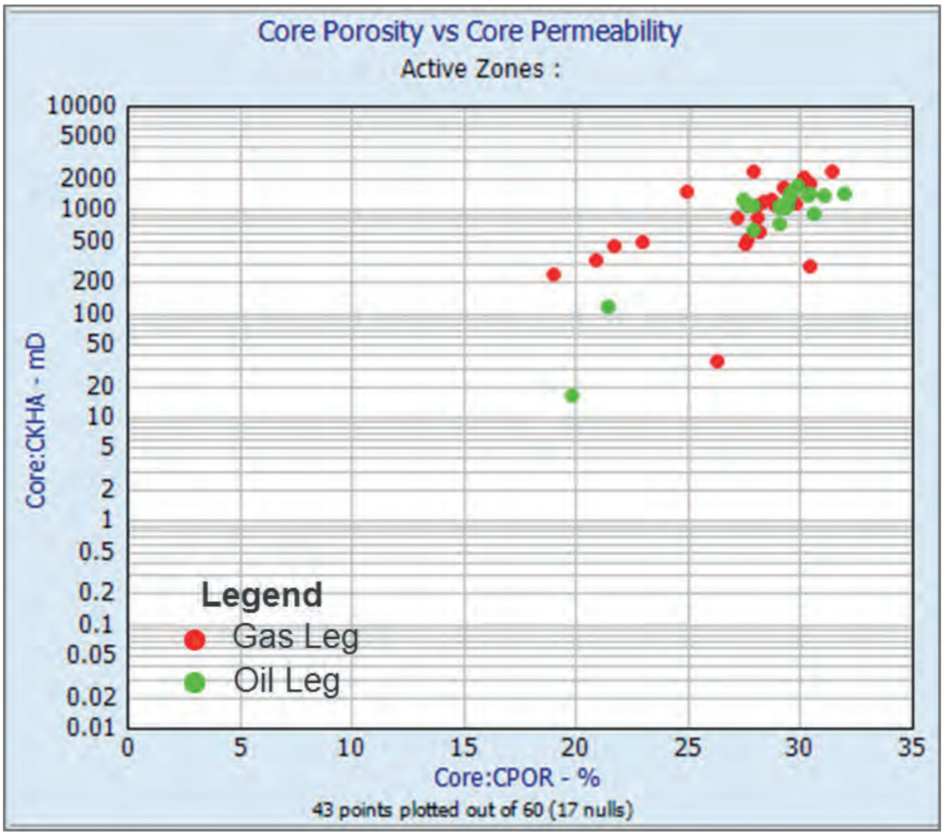

Figure 2.20: Plot of Core Porosity vs Core Permeability Well 15/19-9

ERCE has computed average reservoir properties across the different hydrocarbon zones in the reservoir using cut-offs of >10%phie, <40%Vsh and <60% Sw.

Table 2.7: Petrophysical Sums and Averages, Well 15/19-9

							Net			Pay			
Well	Zone Name	Top	Bottom	Top	Bottom	Gross	Net	N/G	Av Phi	Pay	P/G	Av Phi	Av Sw
		ft MD	ft MD	ft TVDss	ft TVDss	ft TVDss	ft TVDss	v/v	v/v	ft TVDss	ft TVDss	v/v	v/v
15/19-9	BalmoralGas	7,059.25	7,101.75	5,889.33	5,919.62	30.28	14.07	0.465	0.256	14.07	0.465	0.256	0.259
15/19-9	BalmoralOil	7,101.75	7,160.25	5,919.62	5,961.32	41.7	37.42	0.897	0.257	33.77	0.81	0.266	0.32
15/19-9	BalmoralWater	7,160.25	7,381.50	5,961.32	6,120.13	158.82	95.34	0.6	0.223	0	0	---	---
15/19-9	BalmoralRes	7,059.25	7,381.50	5,889.33	6,120.13	230.8	146.84	0.636	0.235	47.84	0.207	0.263	0.302

2.3.6. **Fluid Analysis**

Fluid samples were not taken from Well 15/19-9; the only estimate of oil API is from core samples. There are no measurements of gas properties. The core samples, which were likely already contaminated with drilling fluids, were transported in clingfilm, with chippings in a plastic bag, and as a result likely suffered some loss of light ends during transportation. Any resulting API estimate is therefore more uncertain than those from regular fluid samples.

Both the oil and gas leg residual oil samples showed moderate biodegradation, with the gas leg sample predicting a lower API (28 vs 35 °API). It is unclear whether the oils are different or this is just indicative of uncertainty in samples/measurements. Furthermore, it is unclear from the available samples whether the heavier components in the gas are due to residual oil or wet gas.

The laboratory which undertook the biochemical analysis was uncomfortable with the resulting API predictions, given the compositions and indication of light ends loss, deeming them high, so reduced its predicted ranges to 20-25 °API for the gas leg sample and 30-35 °API for the oil leg sample.

Both pressure and fluid samples were collected from Well 15/19-10 (Stag discovery to the north) but only the MDTs were available for ERCE's review. These data may be indicating a lighter fluid based on the suggested fluid gradient (>30 °API) however Well 15/18b-14 has reported a lower API fluid (20-25 °API).

ERCE has therefore used this information, in conjunction with other known field analogues, and estimates a formation volume factor range of 1.075 / 1.15 / 1.225.

2.3.7. Recovery Factor, Hydrocarbons Initially In Place and Oil Contingent Resources.

ERCE uses probabilistic methods to estimate hydrocarbons in place and Contingent Resources for the Crown discovery.

The principal volumetric uncertainty at Crown is the gross oil leg above contact. ERCE has explored low and high cases for GRV using depth structure sensitivity analysis in combination with low and high case fluid contacts observed in Well 15/19-9. Low and high case gross oil legs maps are illustrated in Figure 2.21

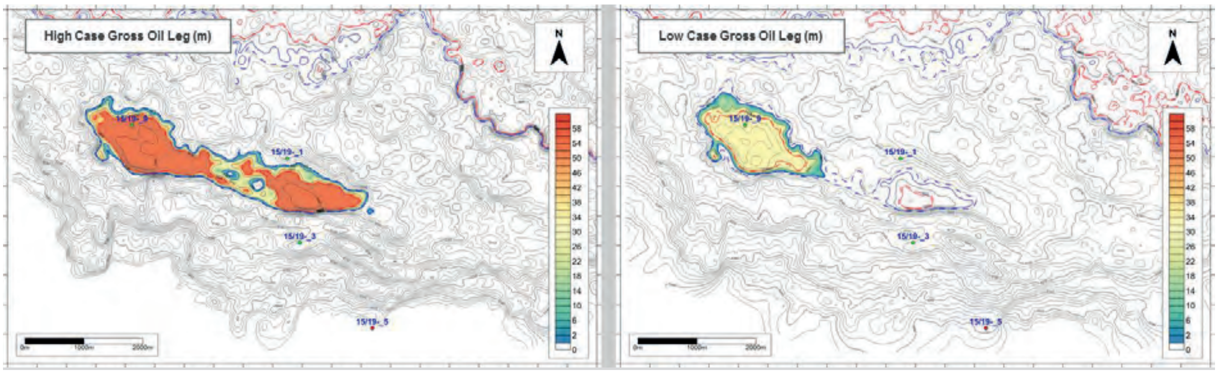

Figure 2.21: Low and High Case Oil Legs (m)

(Grey contours represent depth to top reservoir TVDss, solid blue contour highlights the ODT, dashed blue contour highlights the WUT, red contour highlights GDT and dashed red contour represents OUT. The colourfill represents the gross oil thickness).

ERCE estimates net to gross ratio, porosity and water saturation by reviewing the petrophysical analysis across the different reservoir zones. ERCE is mindful of the impact that varying zone proportions modelled in the low, mid and high case will have on average water saturation and accounts for this. ERCE also applies a range of net to gross ratio (NTG) values to account for how structural variation may have the apparent effect of moving the oil leg to better or worse reservoir zones.

Seismic reprocessing and rock physics studies are part of the work commitments designed to help delineate and de-risk the Crown discovery. This work will also help form the optimal development strategy which at present is undecided. ERCE has considered nearby analogue fields to determine an appropriate range of recovery factors.

A summary of input parameters used in our calculation of STOIIP is presented in Table 2.8.

Table 2.8: Input Parameters - Crown

Licence	Field	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
P2366	Crown	Balmoral	Oil	14	23	40	0.55	0.65	0.75	0.25	0.27	0.29
Licence	**Field**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
P2366	Crown	Balmoral	Oil	0.65	0.70	0.75	1.075	1.150	1.225	0.20	0.28	0.40

Our STOIIP and Contingent Resources (sub-classification Development Unclarified) estimates are presented in Table 2.9. ERCE has reviewed UOG's assessment of chance of development and feel 40% is an appropriate estimation.

Table 2.9: Unrisked Oil Contingent Resources of Crown, Gross and Net to UOG

Licence	Field	Operator / Administrator	Gross Contingent Resources (MMstb)			Working Interest	Net Contingent Resources (MMstb)			Pd
			1C	2C	3C		1C	2C	3C	
P2366	Crown	United Oil and Gas Plc	2.91	6.35	11.48	95.00%	2.76	6.04	10.90	40%

Notes:

1) *Refer to notes under Table 1.2*
2) *Crown carries a 40% chance of development.*

3. Exploration Prospectivity

3.1. Wessex Basin

3.1.1. Introduction

The PL090 and P1918 licence areas within the Wessex basin contain Prospective Resources which have been assessed by ERCE in this report.

The PL090 licence block contains a number of prospects and leads in addition to the contingent resources of the Waddock Cross field discussed in Section 2.1. The licence contains two 3D surveys; the Waddock Cross 3D seismic survey acquired in 2004 and the larger Broadmayne 3D survey, which was acquired in 2013 and lies to the southwest of Waddock Cross. The data have been reprocessed a number of times and the third vintage of reprocessing has been used by UOG and partners in the mapping and identification of leads and prospects (Figure 3.1), including the Broadmayne prospect, which is currently the most mature and to which ERCE has restricted its assessment of Prospective Resources. The data have recently been reprocessed for a fourth time and provisional interpretation performed by UOG over the Broadmayne prospect supports historical mapping and the presence of dip and fault-closure. As such ERCE retains the estimates of unrisked Prospective Resources presented in the April 2017 report but has applied a marginally lower trap risk (and hence higher chance of success) compared to the assessment presented in that report. It is anticipated that mapping and prospect maturation will continue using the results of this recent reprocessing.

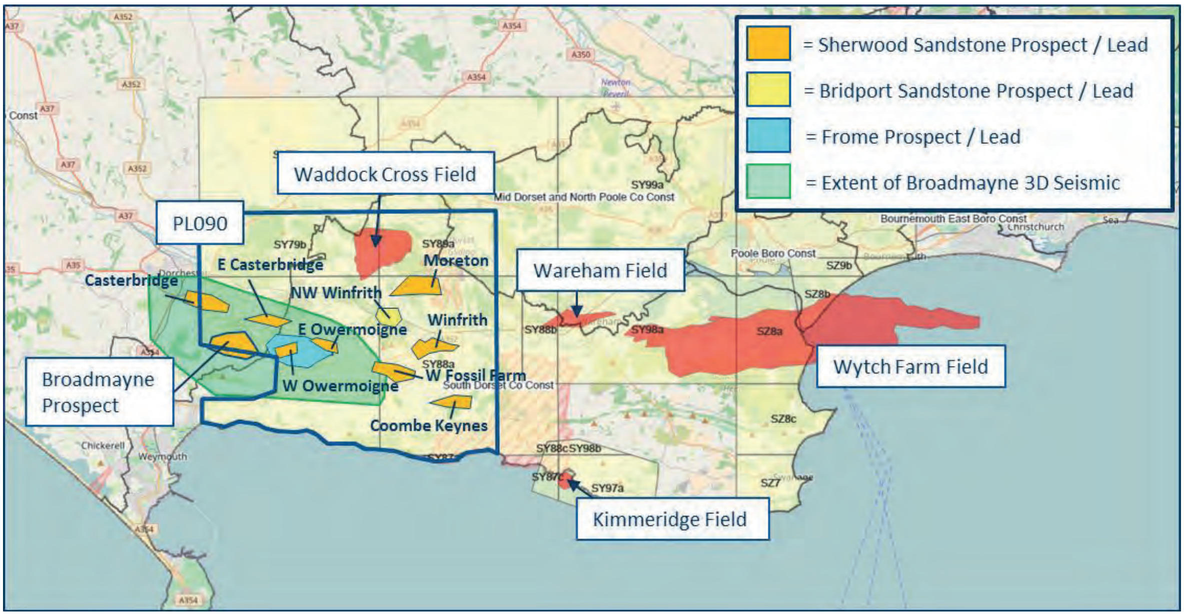

Figure 3.1: Locations of Wessex Basin leads
(Source – Oil & Gas Authority)

The nearby P1918 licence to the south of Wytch farm contains the Colter West prospect, immediately adjacent to Colter East discovery discussed in Section 2.2.

A description of the regional geology and petroleum systems of the Wessex basin is given in Section 2.1.2. The primary exploration play for both prospects is that of the Sherwood Sandstone, charged by long distance migration from the main source kitchen to the east, and trapped within horsts or tilted fault blocks that provide counter dip closure (the regional dip is from west to east).

3.1.2. Broadmayne Prospect (PL090)

The Broadmayne prospect is situated to the southwest of the Waddock Cross field, and is mapped as straddling the PL090 license block at Sherwood Sandstone level.

The Sherwood Sandstone has been penetrated by eight wells within PL090 and the adjacent PEDL072 to the west. All of the wells encountered the Sherwood Sandstone but none encountered hydrocarbons. However, the majority were drilled on poor quality 2D seismic data. Although dry hole analysis is ongoing, the Broadmayne 3D suggests that a number of the wells did not have a valid structural closure, were positioned downdip from the crest, or drilled traps that had evidence of later breach.

The interpretation of the Top Sherwood event is challenging due to structural complexity and poor seismic signal below fast chalk sediments at the surface. The structure is less well defined in the west, in the direction of spill. Reprocessing of the seismic survey has recently been completed and provisional interpretation supports historical mapping and the presence of dip and fault-closure. Figure 3.2 shows a north to south seismic section over the prospect.

ERCE has assessed UOG's seismic interpretation over the Broadmayne structure and has adopted it for our volumetric assessment. A representative depth map is presented in Figure 3.3.

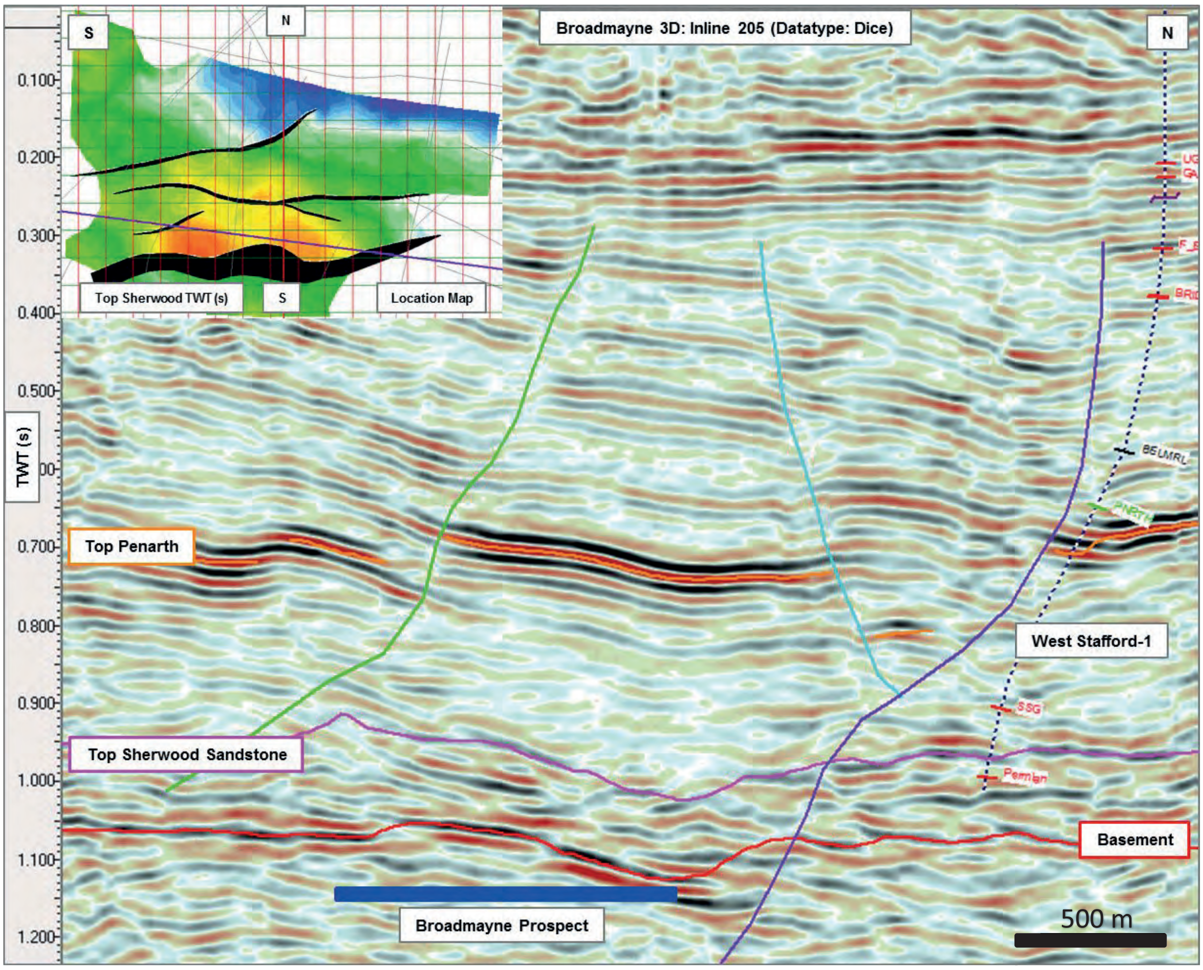

Figure 3.2: N-S Seismic Section Over the Broadmayne Prospect

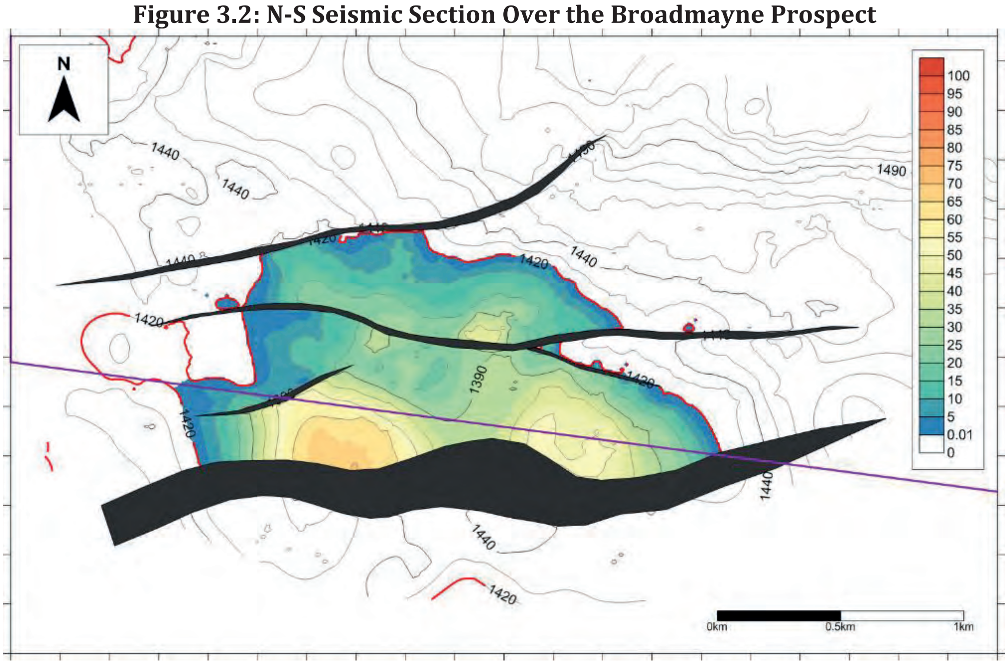

Figure 3.3: Broadmayne Prospect Depth Structure Map (m TVDSS)

(Grey contours represent depth to top reservoir TVDss, red contour highlights the depth at which structural spill occurs and the colourfill represents the gross reservoir thickness above spill depth).

3.1.3. Colter West Prospect (P1918)

The Colter West prospect in licence P1918 appears to be segmented from the Colter East discovery by a northwest to southeast trending fault. The geological history, seismic interpretation and depth structure are identical to Colter East, so are not repeated here.

The western segment is penetrated by the Old Harry well which was drilled in 2000 to the west of Well 98/11-3. Old Harry encountered some thin potentially hydrocarbon-bearing sands near the top of the Sherwood reservoir underlain by water. No tests were undertaken. As a result, ERCE has assessed Prospective Resources for the Colter West structure updip of Old Harry.

3.1.4. Prospective Resources and Geological Chance of Success

ERCE has assessed the undiscovered hydrocarbons in place and oil Prospective Resources for the Broadmayne and Colter West prospects using identical methodology to that used in our assessment of the Waddock Cross field and Colter East discovery respectively.

For the Broadmayne prospect, offset wells Martinstown-1, Chickerell-1 and Coombe Keynes have been used to guide the potential thickness and reservoir properties of the Sherwood. Only the top 100 m of Sherwood Sandstone has been considered in each of the wells as this is the maximum mapped oil column thickness. Estimates of hydrocarbon saturation in the Broadmayne prospect have been made by treating the Wytch Farm Sherwood Sandstone as an analogue.

A summary of input parameters used in ERCE's estimation of the STOIIP for the Broadmayne prospect is presented Table 3.1.

Table 3.1: Input Parameters – Broadmayne Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
PL090	Broadmayne	Sherwood	Oil	20.1	41.5	85.4	0.40	0.50	0.60	0.14	0.18	0.21
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	Best	High	Low	Best	High	Low	Best	High
PL090	Broadmayne	Sherwood	Oil	0.50	0.60	0.70	1.15	1.20	1.25	0.25	0.30	0.35

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources for Broadmayne is presented in Table 3.2.

Table 3.2: Broadmayne Prospect - STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Broadmayne	Egdon Resources UK Limited	5.00	11.10	24.50	13.40	1.50	3.30	7.40	4.00	18.95%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	2U	3U	Mean		Low	Best	High	Mean
Broadmayne	Egdon Resources UK Limited	0.14	0.31	0.70	0.38	30%	0.04	0.09	0.21	0.11

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in Block PL090 (18.95%) and by the proportion of resources which ERCE estimate to fall within the PL090 block boundary (50%).*

Notes:
1) Refer to notes under Table 1.5

ERCE has adopted a four component risk matrix in our assessment of Geological Chance of Success (COS) for the Broadmayne Prospect, comprising source, reservoir (presence and efficacy), trap and seal

ERCE perceives there to be no material risk associated with reservoir presence, efficacy and top seal, based on the results of the offset wells. The dominant risk factors for the Broadmayne prospect are source/migration and trap integrity.

Source encompasses both the presence of source rock material and migration. The presence of producing oil fields in the area confirms the presence of source rocks. Success for Broadmayne relies upon a migration pathway existing to the west of the main source area of the basin into Licence PL090

Trap embraces all the components that define the competency of the closure. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

Our assessment of the COS for the Broadmayne prospect is 30%, as presented in Table 3.3.

Table 3.3: Broadmayne Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Sherwood	0.50	1.00	0.60	1.00	0.30

For the Colter West prospect ERCE generated low and high GRV cases based on fault location sensitivities. ERCE estimates net to gross ratio, porosity and water saturation by reviewing the sensitivity of the petrophysical analysis to varying cut-offs. We also account for an expected improvement in hydrocarbon saturation in the more elevated areas of the field where a shallower structure has been interpreted, based on analogue saturations in the nearby Wytch Farm field. A summary of input parameters used in our calculation of STOIIP is presented in Table 3.4.

Table 3.4: Input Parameters – Colter West Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
P1918	Colter	Sherwood	Oil	40	98	238	0.6	0.7	0.8	0.15	0.18	0.21
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
P1918	Colter	Sherwood	Oil	0.5	0.6	0.7	1.15	1.20	1.25	0.25	0.30	0.35

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources for Colter West is presented in Table 3.5.

Table 3.5: Colter West Prospect – STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter West	Corallian Energy Limited	15	38	95	49	4	11	29	15	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Colter West	Corallian Energy Limited	0.43	1.13	2.87	1.47	50%	0.22	0.56	1.44	0.74

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the P1918 Licence (10.00%).*

Notes:

1) Refer to notes under Table 1.5

ERCE perceives there to be no material risk associated with reservoir presence, efficacy, top seal and source and migration based on the results of the offset wells. The dominant risk factor for the Colter West prospect is trap integrity. The primary risk is a potential seal breach due to known inversion towards the south of the Wessex Basin and possible lack of fault seal.

Our assessment of the COS for the Colter prospect is 45%, as presented in Table 3.6.

Table 3.6: Colter West Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Colter	1	1	0.5	1	0.50

3.2. Southern North Sea

3.2.1. Introduction

Block 29/29c in licence P2264 is located offshore UK in the Southern North Sea (SNS). UOG has agreed to an option to farm-in for a 24% interest, executable upon a firm commitment being made to drill the well becoming applicable to the licence and a farm-in agreement being agreed. The option is valid until expiry of the licence, which will be no earlier than 28 February 2019. The block is surrounded by several gas fields (Figure 3.4), including Gawain to the north, and North Davy due east. The licence is covered by a high-quality 3D seismic survey and numerous 2D seismic lines.

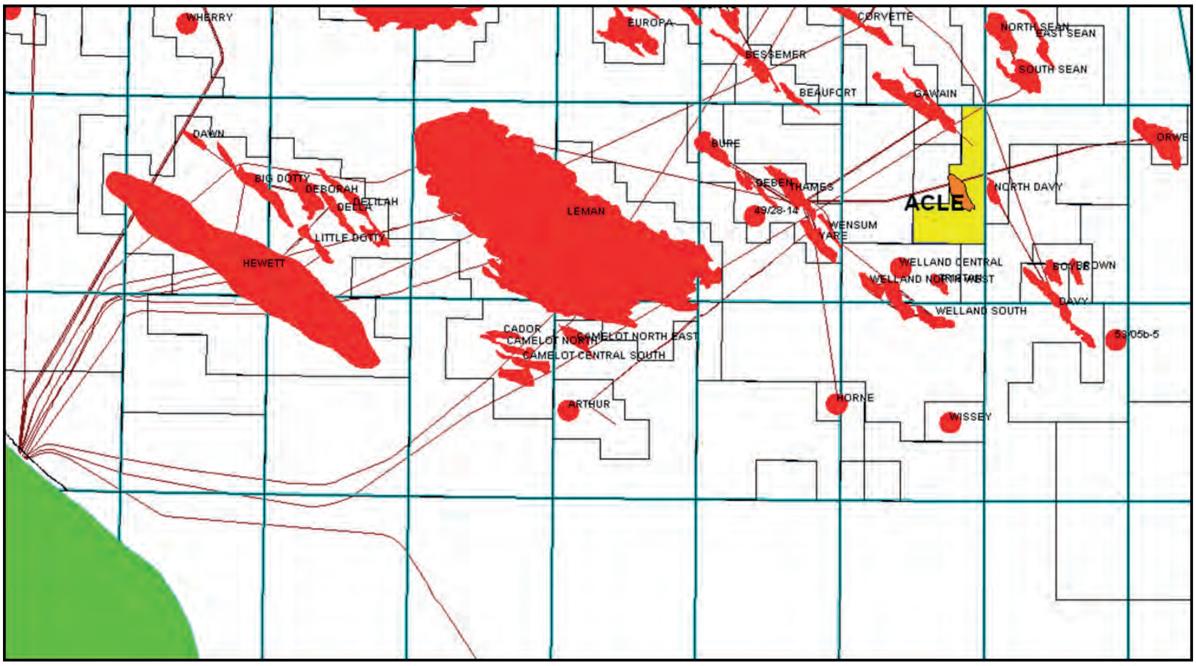

Figure 3.4: Location Map Showing the P2264 licence

The Rotliegend play fairway in the region is well established, comprising aeolian Rotliegend Leman Sandstone reservoir, charged by gas-prone Carboniferous coal measures. Top seal is provided by regional Zechstein evaporites. An example stratigraphic chart for the Southern North Sea (SNS) is shown in Figure 3.5. Tilted fault blocks are typically the dominant trapping mechanism in the Rotliegend play fairway in the SNS.

There have been four wells drilled in the immediate nearby area, all of which encountered the Rotliegend reservoir. Three wells (49/29a-3, 49/29a-10, 49/29c-8) were dry or with gas shows and are thought to have been drilled off structure. Well 49/30a-7A discovered the North Davy gas field in 2000.

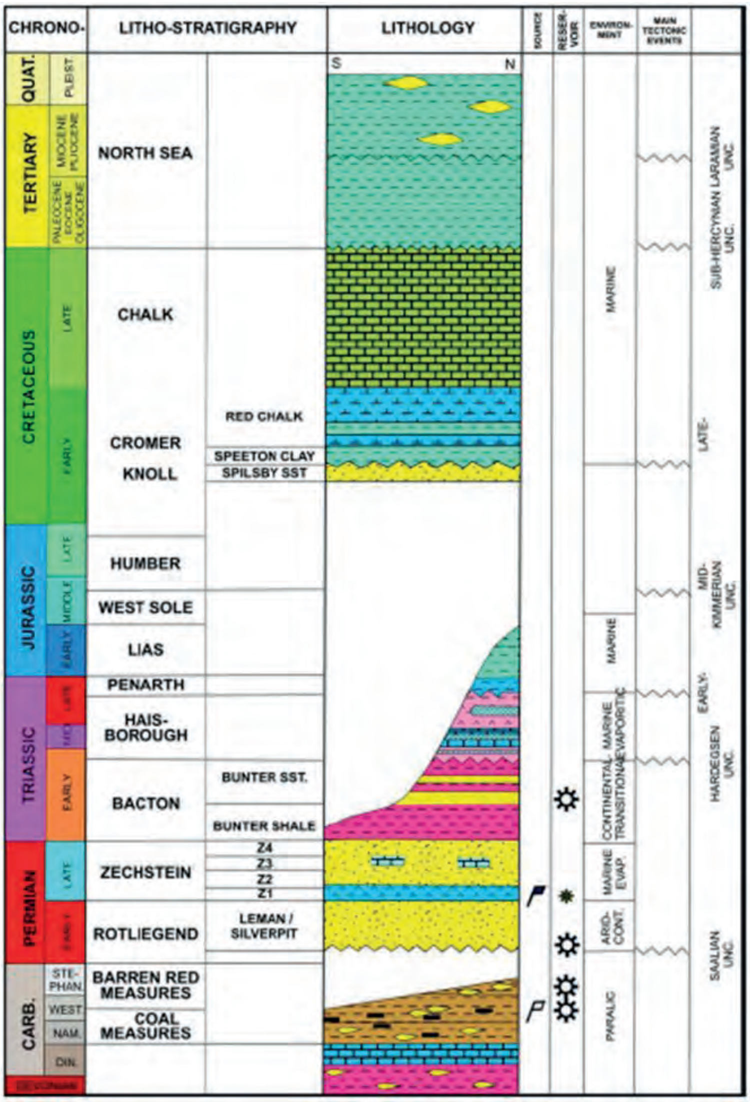

Figure 3.5: Southern North Sea Stratigraphic Column
(Source: Swift Acle Farm Out Presentation)

3.2.2. **Acle Prospect (P2264)**

The Acle prospect is situated to the south of the Gawain field and to the west of North Davy field. The prospect has been mapped at the Top Rotliegend level, and after review ERCE has adopted UOG's Top Rotliegend seismic interpretation for our volumetric analysis.

The prospect comprises a tilted fault block with lateral fault seal to the south defining the spill point for the structure. Figure 3.6 shows a representative southwest to northeast seismic section over Acle.

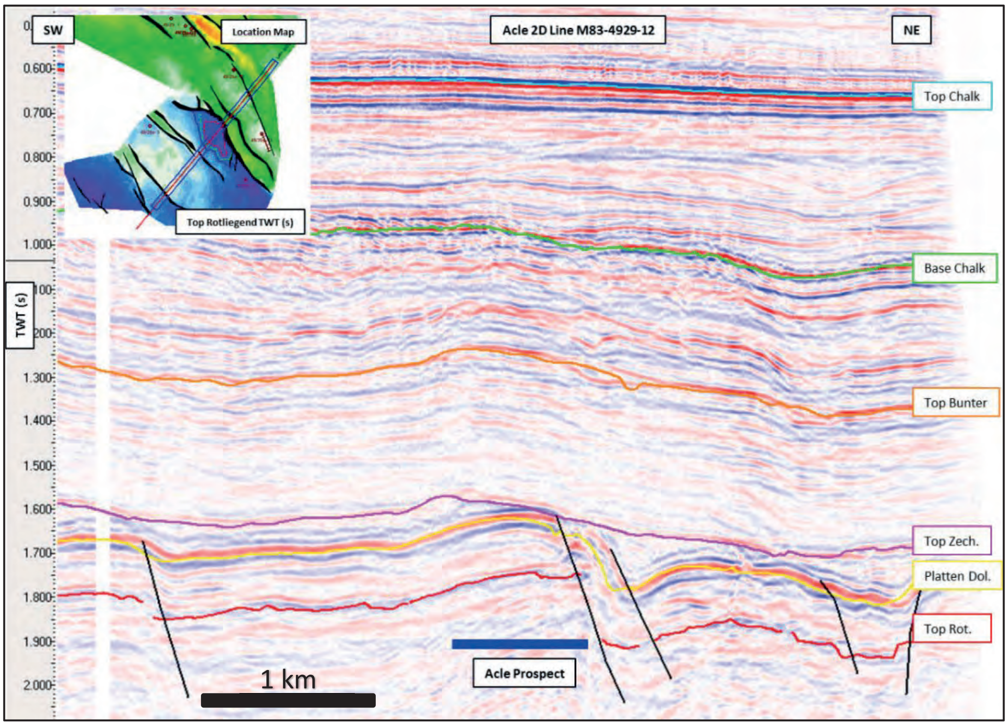

Figure 3.6: 2D Seismic Line across Acle Prospect

Depth conversion is a key uncertainty over the Acle prospect, due to the complex velocity structure of the overlying Zechstein formation, and identification of potential halite pods (Werra Pods) at the southern and western boundaries of the prospect. We have reviewed Swift's depth conversion model, and conducted an independent depth conversion. ERCE's velocity model results in a deeper and lower-relief Top Rotliegend depth structure. ERCE has also assessed GRV sensitivities associated with the position and extent of the laterally sealing faults to the south. Representative depth maps for Swift and ERCE depth conversion models are presented in Figure 3.7.

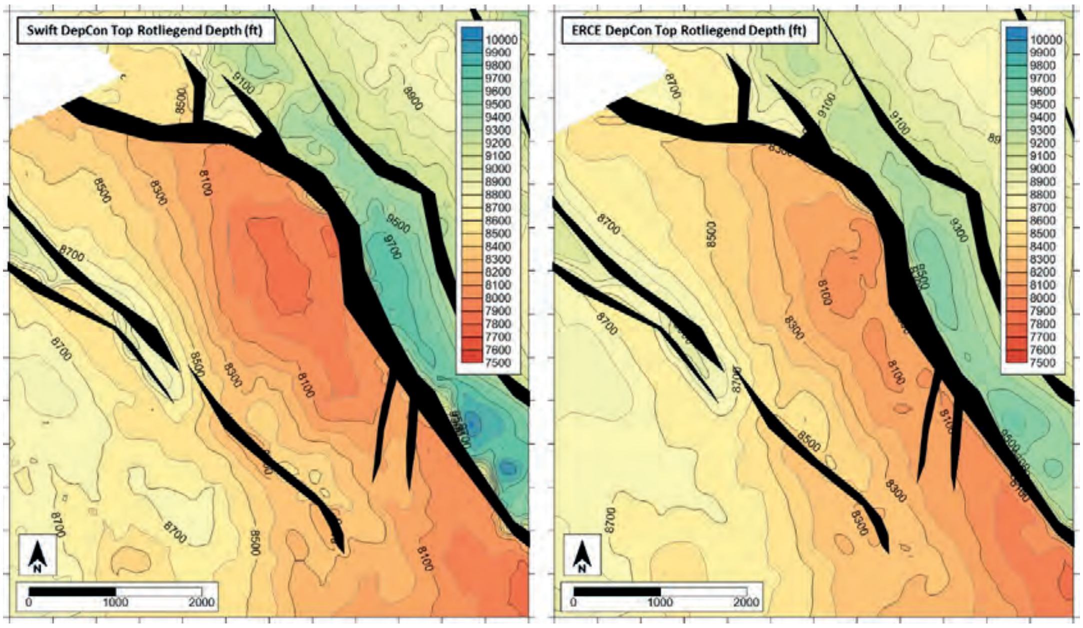

Figure 3.7: Swift (left) and ERCE (right) Top Rotliegend Depth Maps

3.2.3. Prospective Resources and Geological Chance of Success

ERCE uses probabilistic methods to estimate hydrocarbons in place and gas Prospective Resources for the Acle prospect. Low and high case GRVs are derived from the ERCE and Swift depth conversion models respectively, as illustrated in Figure 3.8.

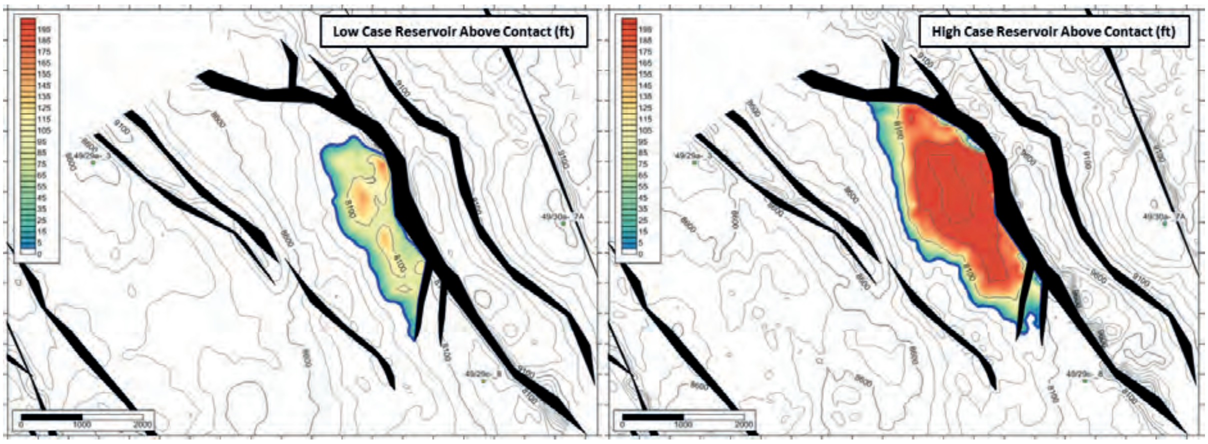

Figure 3.8: Acle Gross Reservoir Above Spill Maps

(Grey contours represent depth to top reservoir TVDss (ft), blue contour highlights the depth at which structural spill occurs and the colourfill represents the gross reservoir thickness above spill depth).

Offset Wells 49/29c-8 and 50/26b-6 have been used to guide our estimates of reservoir properties. Estimates of hydrocarbon saturation have been made from SNS gas field analogues. A summary of input parameters used in ERCE's estimation of the GIIP for the prospect is presented in Table 3.7.

Table 3.7: Input Parameters – Acle Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
P2264	Acle	Rotliegend	Gas	58	127	278	0.85	0.90	0.95	0.15	0.20	0.25
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**GEF (scf/rcf)**			**Recovery Factor (frac)**		
				Low	**Best**	**High**	**Low**	**Best**	**High**	**Low**	**Best**	**High**
P2264	Acle	Rotliegend	Gas	0.75	0.80	0.85	200	210	220	0.70	0.75	0.80

A summary of our estimates of undiscovered GIIP and gas Prospective Resources is presented in Table 3.8.

Table 3.8: Acle Prospect - GIIP and Gas Prospective Resources

Prospect	Operator/ Administrator	GIIP (Bcf)				Gross Unrisked Prospective Resources (Bcf)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Acle	Swift Exploration Limited	57	132	301	163	42	99	226	122	24%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (Bcf)**				**COS**	**Net Risked Prospective Resources (Bcf)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Acle	Swift Exploration Limited	10	24	54	29	43%	4.4	10.2	23.3	12.6

- **Net Unrisked and Risked Prospective Resources assume execution of the Farm-In Option to Licence P2264 (24.00%)*

Notes:
1) Refer to notes under Table 1.5

ERCE has adopted a four-component risk matrix in our assessment of the COS for the Acle prospect, comprising source, reservoir (presence and efficacy), trap and seal.

ERCE perceives there to be low risk associated with source, reservoir presence, efficacy and top seal, based on the results of the offset wells, and density of surrounding gas fields. The dominant risk factor for the Acle prospect is the trap integrity. Trap embraces all the components that define the competency of the closure. The prospect relies on the presence of a laterally sealing fault to the south, and there is significant uncertainty on the associated position, throw and fault seal potential.

Our assessment of the COS for the Acle prospect is 43% as presented in Table 3.9.

Table 3.9: Acle Risk Matrix

Prospect	Source	Reservoir	Trap	Seal	COS (frac)
Acle	0.95	0.95	0.50	0.95	0.43

3.3. Jamaica

3.3.1. Introduction

The Walton-Morant licence area is situated offshore Jamaica and covers a large area of 32,065 km^2 (Figure 3.9). The PSA became effective on 1st November 2014 and Tullow is the operator. UOG has signed an agreement with Tullow to farm-in to the Walton-Morant Licence at a 20% equity interest. This will involve paying a 20% share of costs. In May 2018 Tullow completed the acquisition of 2250 km^2 of 3D seismic data which was designed to concentrate on the Colibri prospect. Since the acquisition the data have been reprocessed and a number of 3D seismic volumes and derived attributes have been generated.

The licence contains the Pedro Bank carbonate platform and the Walton and Morant Basins, of which the Walton Basin is the primary exploration focus as this contains siliciclastic reservoirs located within a thermally mature kitchen area.

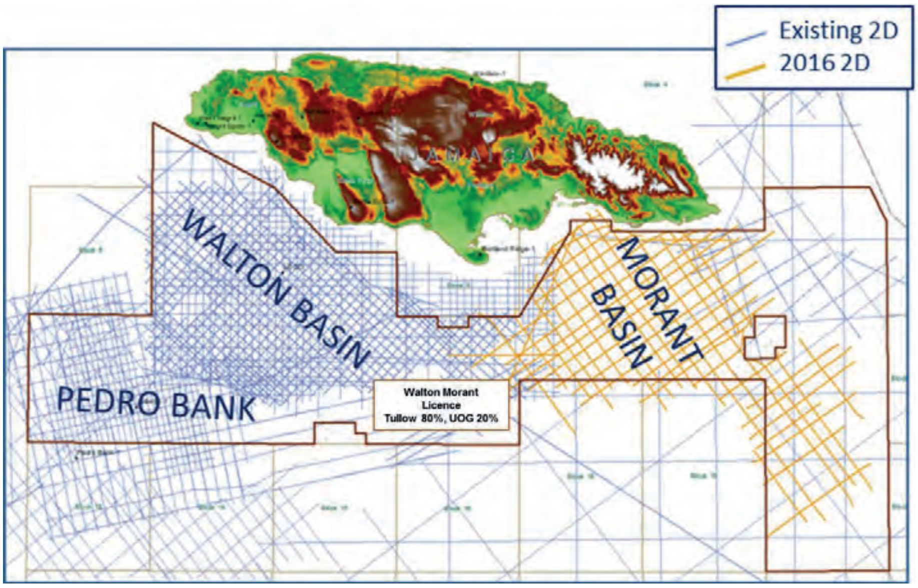

Figure 3.9: The Walton Morant Licence, offshore Jamaica
(Source: Tullow)

The Walton Basin is an Early Tertiary rift basin situated on the eastern margin of the Nicaragua Rise.

The principal reservoir target is the Middle Eocene Guy's Hill formation, which exhibits good reservoir quality both onshore and offshore, with an average of 20% porosity at outcrop. The Guy's Hill Formation comprises a fluvio-deltaic-shallow marine succession in stacked parasequences which have been observed to reach up to 320 m gross thickness onshore. Well Arawak-1 is the nearest offshore penetration of potential Guy's Hill correlatives located approximately 70km to the west of the prospect, this is interpreted to contain a gross thickness in excess of 220m. A potential lack of continental clastic input has been a concern for reservoir quality and extent in the region. However, evidence of southerly directed palaeocurrents and palaeontological data suggest Jamaica was receiving sediment from the Maya – Chortis continental block in the Eocene epoch. This implies the presence of delta mouth, shoreface and/or submarine fan sands with good reservoir properties in offshore areas.

The proposed source rocks in the region are Eocene prodelta-marine shales and Cretaceous marine shales, which are observed onshore and at outcrop. Sedimentological models and analogues predict thicker and more oil prone marine shales offshore. Seeps have been observed onshore, and there have been two positive offshore seep surveys. Although a definitive correlation to a particular source rock is yet to be achieved, this suggests an effective and mature regional source. Extensive maturity modelling suggests significant oil would have been expelled from Eocene kitchens in both the Walton and Morant basins.

The recently acquired and processed 3D seismic data covering the Colibri prospect better images faults which could provide migration pathways from source to reservoir. The 3D seismic also reveals features which are positive indications that fluid movement has taken place within the basin. These include pock marks at seabed and bright amplitude abutting deep seated faults. This additional information has allowed ERCE to reduce the risk associated with source and migration.

Seal is provided by the widely distributed transgressive shales, marls and tight limestones of the Chapelton formation, which directly overlies the Guy's Hill Formation.

Structurally, the area sits within an extensional horst and graben-style basinal setting with large tilted fault blocks and basement highs as trapping mechanisms.

The regional stratigraphy of the area is summarised in Figure 3.10.

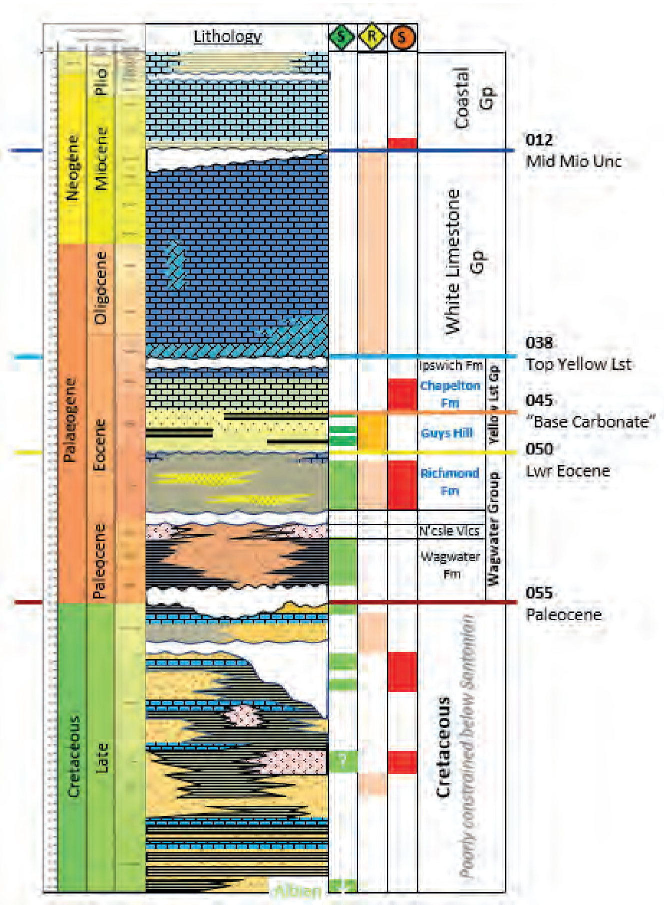

Figure 3.10: Regional Stratigraphy, offshore Jamaica
(Source: Tullow)

Historically, exploration focused on Cretaceous targets and to date eleven wells have been drilled, of which nine wells were onshore and two were offshore. Many of the targets were defined only by surface geology whilst others were based on poor data and UOG's current interpretation is that the wells were not valid structural tests. However, all but one of the wells exhibited hydrocarbon shows.

Well Arawak-1 was one of the last wells drilled in Jamaica in 1982 and exhibited wet gas shows. The well targeted Cretaceous carbonates in a four way dip closed anticline structure, but the reservoir was not encountered as prognosed and the well was plugged and abandoned at a depth of 4,588 metres. The well did intersect over 200 m of sands possibly belonging to the Guy's Hill formation with a net to gross ratio of 46% and a log derived porosity of 14%, at a depth of around 4000 m MD, near TD.

3.3.2. Colibri Prospect (Walton-Morant)

The Colibri prospect is situated in the Walton Basin in water depths of approximately 750 m (Figure 3.11). The prospect is a well-defined fault-bounded structure with onlap and drape. The basinal position suggests overlying pelagic shales and marls will likely form a seal. The 3D seismic data demonstrate that some faulting propagates to seabed, implying the possibility of trap breach. The prospect is well positioned to receive charge from surrounding Eocene and/or Cretaceous kitchens, and is located close to the Blower Rock oil seep. The improved imaging provided by the 3D seismic data provides positive evidence for migration pathways and fluid movement through the Walton

Basin. The area has also been interpreted by Tullow to sit within the Guy's Hill Formation depositional fairway.

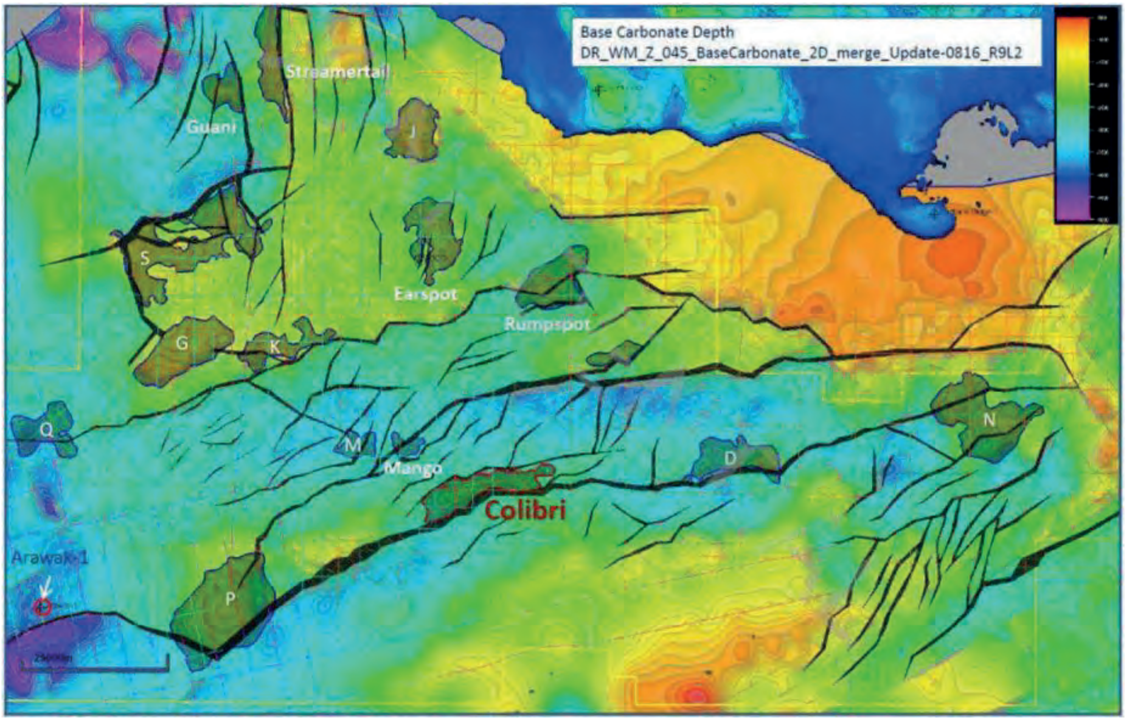

Figure 3.11: Location of Colibri and associated leads in the Walton Basin
(Source: Tullow)

ERCE has reviewed both Tullow's and UOG's revised 3D seismic interpretation over the Colibri structure and following audit has adopted interpretations as valid models from which to derive a volumetric range. A west to east and south to north seismic section across the Colibri prospect illustrating these interpretations for comparison are shown in Figure 3.12 and Figure 3.13 respectively.

ERCE has assessed the Tullow processing velocity depth conversion model and performed comparisons against independent layer cake models that predicts an increase in velocity with increasing depth below seabed. The rate of velocity increase ($0.7s^{-1}$) was determined from regressions of sonic log velocities from Well Arawak-1. However, it is noted that this well is located on the Pedro Bank and encountered different lithologies than prognosed for the more basinal location of the Colibri prospect. ERCE have therefore calibrated the layer cake model to a crestal depth predicted by the processing velocities. ERCE used both the linear model and processing velocity model as alternative base cases for further stochastic sensitivity analysis for the Colibri prospect.

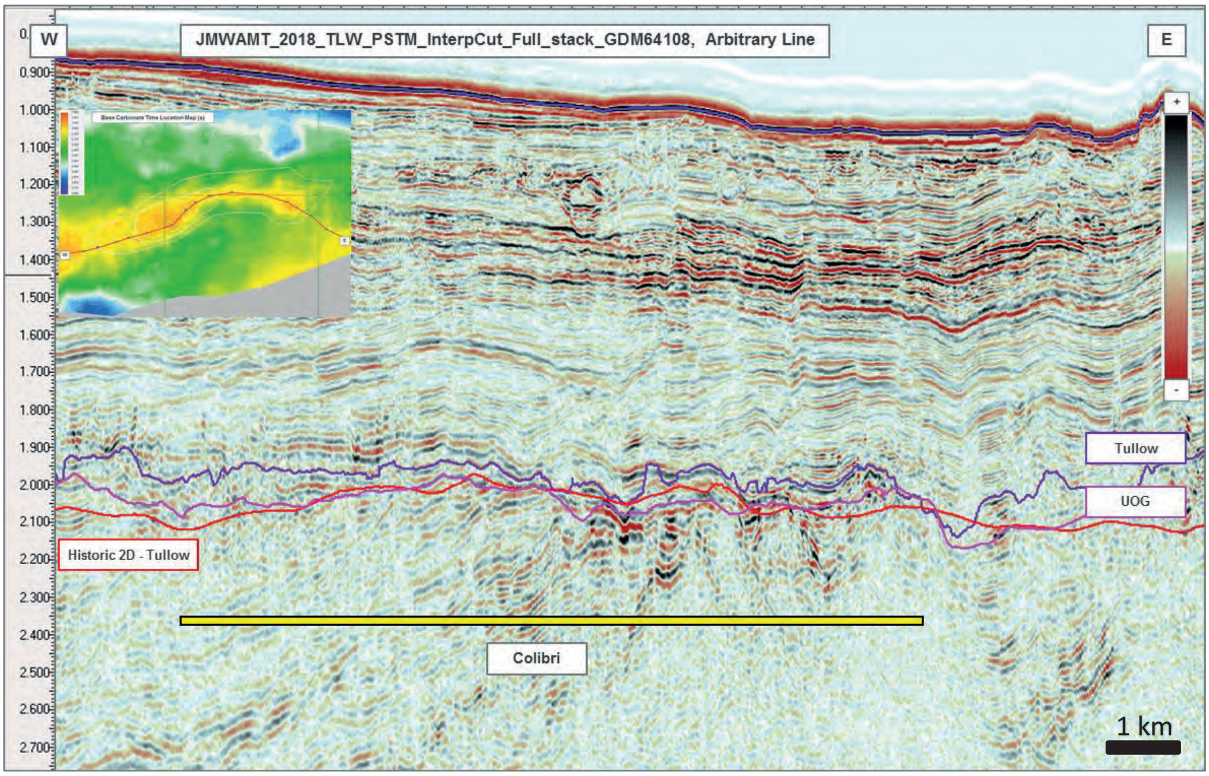

Figure 3.12: W-E Seismic Section Over the Colibri Prospect

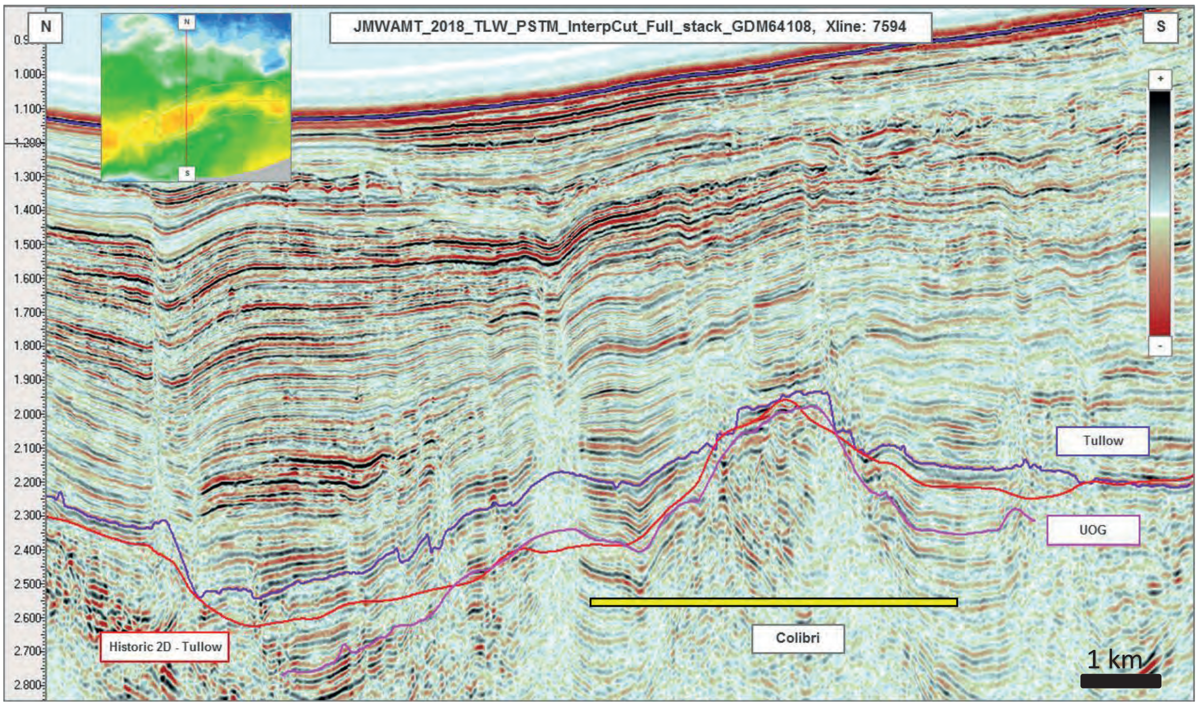

Figure 3.13: S-N Seismic Section Over the Colibri Prospect

3.3.3. Prospective Resources and Geological Chance of Success

ERCE uses probabilistic methods to estimate hydrocarbons in place and oil Prospective Resources for the Colibri prospect.

ERCE has applied stochastic uncertainty modelling to our base case depth structures to assess the GRV range of the Colibri prospect. An uncertainty of up to 5% in depth below mudline has been assumed and used to condition the sequential gaussian simulation (SGS) surfaces. The resulting high and low case closures are shown in Figure 3.14.

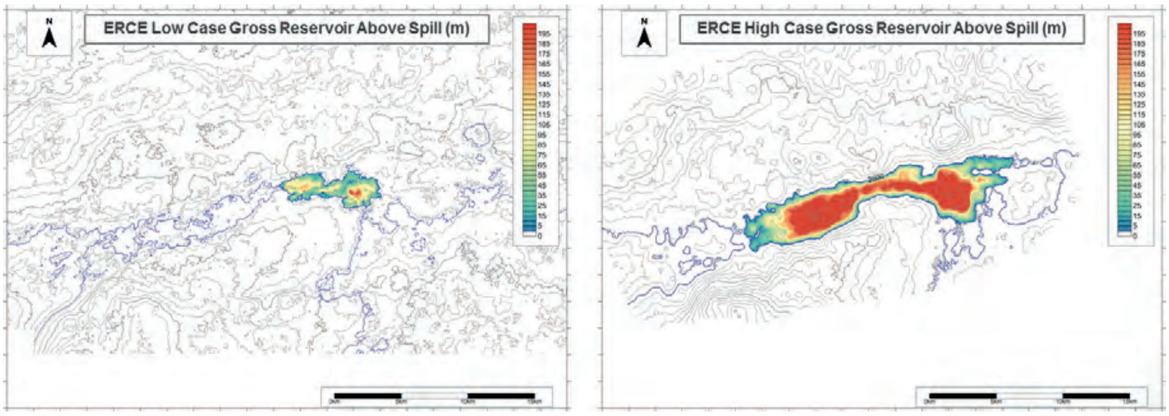

Figure 3.14: Colibri Prospect, Reservoir Height Above Contact Maps (m TVDss)
(Grey contours represent depth to top reservoir TVDss, blue contour highlights the depth at which structural spill occurs and the colourfill represents the gross reservoir thickness above spill depth).

Offset Well Arawak-1 together with outcrop studies and analogues have been used to guide the potential thickness and reservoir properties of the Guy's Hill Formation over the Colibri prospect. Estimates of hydrocarbon saturation in the Colibri prospect have been made by using an industry analogue database. A summary of input parameters used in ERCE's estimation of the STOIIP for the Colibri prospect is presented in Table 3.10.

Table 3.10: Input Parameters – Colibri Prospect

Block	Prospect	Reservoir	Phase	GRV (MMm3)			NTG (frac)			Porosity (frac)		
				Low	Best	High	Low	Best	High	Low	Best	High
Walton Morant	Colibri	Guy's Hill	Oil	772	2259	6608	0.20	0.40	0.60	0.12	0.19	0.25
Block	**Prospect**	**Reservoir**	**Phase**	**HC Saturation (frac)**			**Bo (rb/stb)**			**Recovery Factor (frac)**		
				Low	Best	High	Low	Best	High	Low	Best	High
Walton Morant	Colibri	Guy's Hill	Oil	0.50	0.65	0.80	1.12	1.21	1.30	0.15	0.25	0.45

A summary of our estimates of undiscovered STOIIP and oil Prospective Resources is presented in Table 3.11.

Table 3.11: Colibri Prospect - STOIIP and Oil Prospective Resources

Prospect	Operator/ Administrator	STOIIP (MMstb)				Gross Unrisked Prospective Resources (MMstb)				*Working Interest
		Low	Best	High	Mean	1U	2U	3U	Mean	
Colter West	Corallian Energy Limited	15	38	95	49	4	11	29	15	10%
Prospect	**Operator/ Administrator**	**Net Unrisked Prospective Resources (MMstb)**				**COS**	**Net Risked Prospective Resources (MMstb)**			
		1U	**2U**	**3U**	**Mean**		**Low**	**Best**	**High**	**Mean**
Colter West	Corallian Energy Limited	0.43	1.13	2.87	1.47	50%	0.22	0.56	1.44	0.74

- **Net Unrisked Prospective Resources have been calculated by multiplying Gross Unrisked Prospective Resources by UOG's working interest in the Walton-Morant Licence (20.00%)*

Notes:
1) *Refer to notes under Table 1.5*

Our assessment of the risk for the Colibri play is 54%, with the prospect risk at 36%, leading to a Geological chance of success as 20%, as presented in Table 3.12. The recently acquired 3D seismic data shows positive evidence of fluid movement and hydrocarbon presence in the basin and ERCE have therefore reduced the risk associated with play source and prospect migration since the last assessment. The dominant prospect risk is reservoir efficacy and presence, given the sparsity of wells and uncertain reservoir distribution in the basin.

Table 3.12: Colibri Play and Prospect Risk Matrix

Play Element	Risk
Source	0.85
Reservoir Presence	0.80
Seal	0.80
Combined Play Risk	0.54

Prospect Risk	Colibri
Trap	0.80
Reservoir efficacy (presence)	0.50
Migration	0.90
Combined Prospect Risk	0.36

Geological Chance of Success (GCOS)	0.20

4. SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, Version 1.01, as revised in June 2018 and updated in November 2018 (PRMS).

The full text of the PRMS document can be viewed at:

https://secure.spee.org/resources/reserves-definitions-committee-rdc

PRMS classifies resources into discovered and undiscovered, and defines the recoverable resources classes of; Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

A graphical representation of the PRMS resources classification framework can be seen below in Figure A. The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, which is the chance that a project will be committed for development and reach commercial producing status.

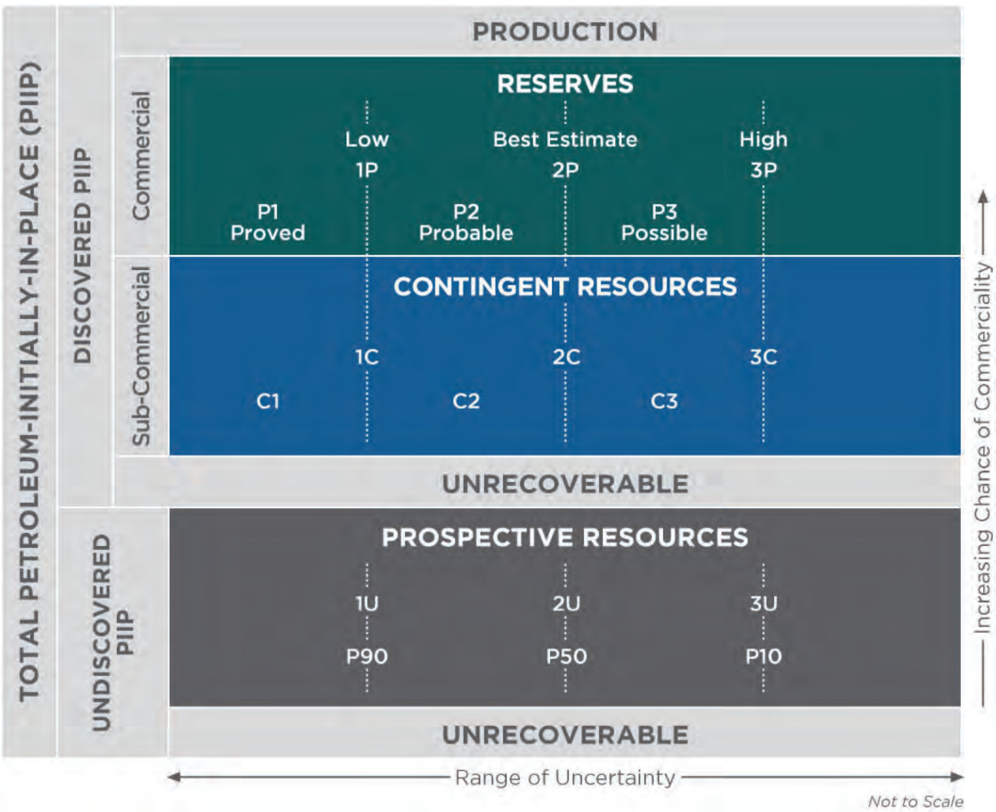

Figure A: PRMS Resources classification framework
(Source: PRMS, Version 1.01; page 1, Figure 1.1)

As illustrated below in Figure B, development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

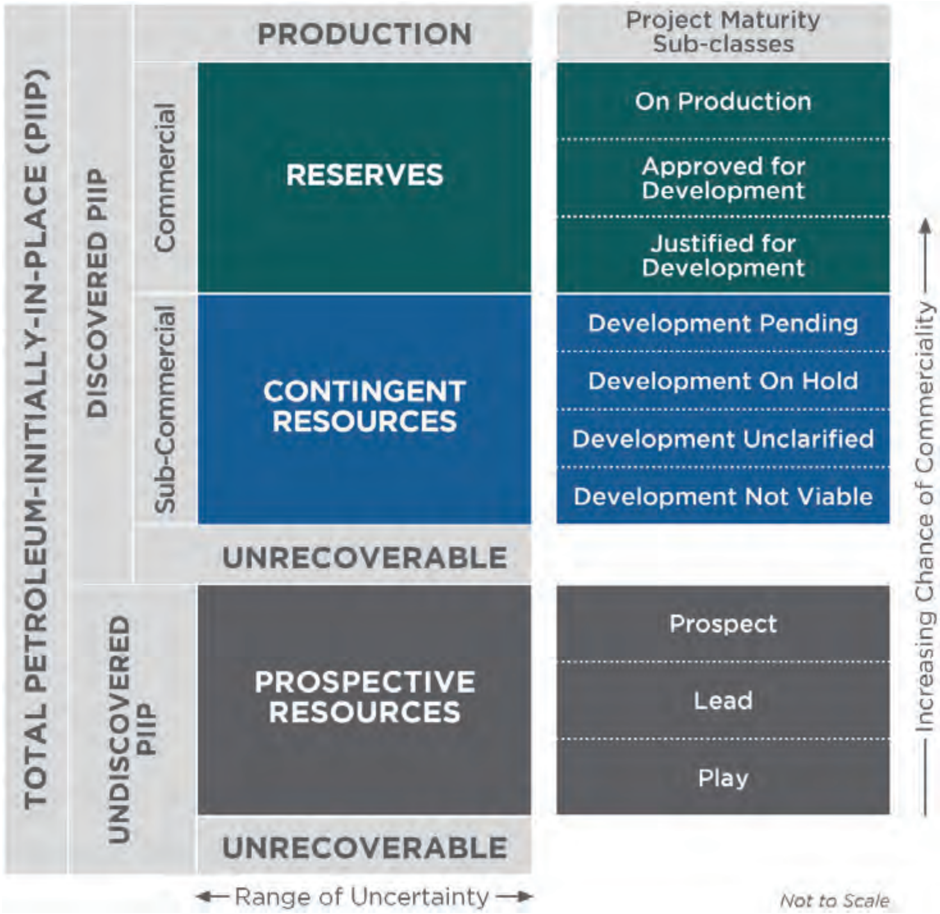

Figure B: PRMS Resources sub-classes
(Source: PRMS, Version 1.01; page 8, Figure 2.1)

A summary of key definitions of the PRMS Reserves and Resource categories, classes and sub-classes can be found in Tables 1-3 and a glossary of selected PRMS terms can be found in Table 4, below:

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see PRMS Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see PRMS Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

Classes/Sub-classes	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Selected Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Low/Best/High Estimate	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an accumulation or project.

5. Nomenclature

5.1. Units and their abbreviations

bbl	barrel
bbl/d	barrels per day
ft	feet
ftTVDSS	feet subsea
km	kilometres
m	metres
M or MM	thousands and millions respectively
md	millidarcy
mTVDSS	metres subsea
rcf	cubic feet at reservoir conditions
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb/d	stock tank barrels per day

5.2. Terms and their abbreviations

Bo	oil shrinkage factor or formation volume factor, in stb
CPI	computer processed information log
DST	drill stem test
GEF	gas expansion factor
GIIP	gas initially in place
GRV	gross rock volume
GWC	gas water contact
NTG	net to gross ratio
OWC	oil water contact
Phi	porosity
PSDM	post stack depth migration
PSTM	post stack time migration

PVT	pressure volume temperature experiment
STOIIP	stock tank oil initially in place
Sw	water saturation
TVD	true vertical depth

PART IX

COMPETENT PERSON'S REPORT – CGG SERVICES (UK) LIMITED

CGG Services (UK) Limited

COMPETENT PERSONS REPORT

PODERE GALLINA LICENCE, ITALY

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DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG and its employees who worked on preparation of this report, are independent of United Oil & Gas plc (UOG) and their directors, senior management and other advisers; have no economic or beneficial interest (present or contingent) in the company or in any of the mineral assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG have used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

In undertaking this valuation CGG have used data supplied by UOG in the form of geoscience reports, seismic data and engineering reports. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that UOG will have in the Properties, as communicated by UOG. CGG has not verified nor do CGG make any warrant as to UOG's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserve; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the UOG.

CGG affirm that from 1st October 2018 (the cut-off date for inclusion of data) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of UOG.

The report has been prepared and is presented in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM

Guidance Note”). This report conforms with the guidelines and definitions of the Petroleum Resources Management Systems (PRMS) (2007 and 2011) as published by the Society of Petroleum Engineers (SPE). Further details of these definitions are included in Appendix A of the CPR.

Conditions of Usage

If substantive new data or facts become available or known after the date of issue of this report, then this report should be updated to incorporate all relevant new information.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by UOG for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on UOG’s own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The copyright of this CPR document remains the property of CGG. The CPR may not be used for any other purpose without the prior written approval of CGG. The recipient should also note that this document is being provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by CGG.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

CGG Services (UK) Limited Reference No: BP521				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
1	22nd February 2019	AS, TU, PW	AJW	Final report

Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
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1 EXECUTIVE SUMMARY

This report has been prepared for the Directors of:-

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CGG is acting as UOG's Competent Person as defined by the rules made by the London Stock Exchange, governing the admission of securities to AIM (the AIM Rules) and the 'Guidance Note For Mining, Oil and Gas Companies' issued by the AIM team of the London Stock Exchange in June 2009 (AIM Guidance Note) in relation to the Company's interest in the Podere Gallina exploration licence, located in the Po Valley, northern Italy. In accordance with the engagement letter between CGG and UOG dated 3rd January 2019, CGG has prepared an independent Competent Person's Report in respect of the Company's interest in the Podere Gallina exploration licence in connection with the proposed application for admission to trading on the AIM Market (AIM) of the London Stock Exchange plc (London Stock Exchange) of the entire issued share capital of the Company (Admission) and the issue of an admission document (Admission Document) prepared in accordance with the AIM Rules and the AIM Guidance Note.

In January 2018, CGG was commissioned to prepare a Competent Person's Report on the Podere Gallina licence for UOG and this report was published in the Company's Prospectus dated 30 April 2018. This report has now been updated: 1) to reflect the submission in May 2018 of an application to the Italian Ministry for a Production Concession, which included a development plan, and subject to award of the Production Concession, which in January 2019 has been granted preliminary approval by the Italian Government, this has enabled the recoverable volumes to be classified as Reserves within this CPR, and 2) to conform with the requirements of AIM, in particular with the AIM Guidance Note.

1.1 Location

The Po Basin runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years. The Podere Gallina Licence is located approximately 10 km to the east of Bologna, and about 30 km from the coast in the Ferrara and Bologna provinces of the Emilia-Romagna region.

Figure 1.1 Location map for Podere Gallina licence

1.2 Data sources

In completing this evaluation, CGG have independently reviewed information and checked the validity of interpretations provided by UOG, as well as utilising complementary information from the public domain. CGG have produced several previous CPRs on the Podere Gallina Licence over the last four years for the operator and UOG, and as a result are familiar with the geology. Much of the data supplied by UOG for this report was in the form of updates to existing data previously provided to and reviewed by CGG. In conducting their evaluation, CGG have accepted the accuracy and completeness of data supplied by UOG, and have not performed any new interpretations, simulations or studies. Resource volumes presented in this report have been worked up independently by CGG.

1.3 Licence Description

The Podere Gallina Licence is located in the Po Valley plain, and covers an area of 506 square kilometres. The currently shut-in Selva gas field lies within this licence area. This field, operated by ENI, the Italian oil and gas multinational, produced 83 Bcf over a 35 year period from 15 wells. Production ceased in 1984.

As a result of a farm-in agreement between Po Valley Operations Pty Ltd (PVO) and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well that was drilled in Q4 2017. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Table 1.1 Podere Gallina licence details

Operator	UOG Interest (%)	Status	Licence expiry date	Licence Area
PVO	20%	Exploration	3rd February 2018*	506 km^2

* In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorization time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from February 3, 2018. The application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law.

1.4 Reserves

A summary of the resources associated with the “Selva Stratigraphic” redevelopment opportunity and the three prospects, both gross and net, in accordance with the 2007 Petroleum Resource Management System (PRMS) published by the SPE, are shown in the table below.

The volumes associated with the “Selva Stratigraphic” redevelopment opportunity have been updated since the previous CPR (April 2018), which incorporated the results of the Podere Maiar-1 well. Given that the PM-1 well had further de-risked progression towards a commercial development, in May 2018 an application was submitted for a Production Concession, allowing gas production to commence from the PM-1 well after tie-in to the gas network pipeline nearby. This application included a development plan, and subject to award of the Production Concession, which in January 2019 was granted preliminary approval by the Italian Government, the recoverable volumes can be classified as Reserves within this CPR.

As the submitted development plan is based solely on production from the PM-1 well, in the 1P and 2P cases, CGG have considered a situation in which the entire structure is not drained, leading to a reduction in numbers compared to the previously reported 1C and 2C Contingent Resources, which were not based on a specific development plan. However, the 3P Reserves remain unchanged from the previously reported 3C Contingent Resources, as the possibility remains that all of the mapped volumes could be drained by the existing PM-1 well. A clearer picture will emerge on this once there is production history from the well.

CGG has reviewed the relevant application documents in detail and reports the following Reserves and Resources for the assets. In light of the preliminary award of the Production Concession which was awarded in January 2019 by the Italian authorities, the “Selva Stratigraphic” redevelopment is classified as reserves.

These volumes have been based on integrating all of the geological and historic production data, including the well test results, to arrive at a range of reserves that reflects the uncertainties that exist in the Selva field.
Once production has started, over time it is expected that this range of reserves will narrow as the production history gives certainty to the recoverable volumes.

Table 1.2 Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG

Selva Stratigraphic Trap	Gross (MMscm)			20% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	10	26	42	PVO
C2 Sand	69	250	637	14	50	127	
Total	**117**	**379**	**846**	**23**	**76**	**169**	

** The net attributable may not add due to rounding error.*

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project for a 100% field interest and respective UOG net interest. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

Table 1.3 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	2.0	5.5	9.2	PVO
Low	7.6	21.3	36.2	1.5	4.3	7.2	
High	12.7	33.5	56.0	2.5	6.7	11.2	

CGG’s gas price assumption follows the forward Italian PSV spot gas price curve until 2025, and thereafter escalates at 2% per year. Low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/- 20% for 2021 onwards.

1.5 Prospective Resources

The table summarise the prospective resources identified within the licence. A 3D seismic survey is also being planned, which will help delineate any further opportunities for undrained gas within the Selva structure.

Table 1.4 Summary of Gas Prospective Resources by Prospect

	Gross (MMscm)				
Name	**Low**	**Best**	**High**	**Risk factor**	**Operator**
Cembalina	59.5	93.5	133.1	51%	PVO
Fondo Perino	288.9	413.5	580.6	34%	PVO
East Selva	824.1	985.6	1149.8	30%	PVO

Notes:-

1. *Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Prospective resources have both an associated chance of discovery and a chance of development*
3. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates*
4. *Prospective Resources are stated before the application of a risk factor and an economic cut-off*
5. *Full definitions of the Prospective Resource categories can be found in Appendix A*
6. *The risk factor means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*

1.6 Conclusion

CGG have reviewed the available information on the Podere Gallina licence in the Po Valley in northern Italy and conclude that UOG has performed a reasonable interpretation of the available data. CGG believe that the figures in this report reflect the potential for the field, given current knowledge. It should be noted that the reserves classification is subject to the award of a Production Concession. Although preliminary approval by the Italian Government was granted in January 2019, it should be noted that the award of the final production licence may be affected by the new law of February 11th 2019 that relates to upstream oil and gas activities.

2 INTRODUCTION

This independent Competent Person's Report (CPR) was prepared by CGG at the request of United Oil & Gas plc (UOG). The report evaluates reserves and resources associated with the Podere Gallina licence in the Po Valley in northern Italy, which is operated by PVO.

In January 2018, CGG was commissioned to prepare a CPR on the Podere Gallina licence for UOG, and this report was published in the Company's Prospectus dated 30 April 2018. This report has now been updated to reflect the submission in May 2018 for a Production Concession, which included a development plan. Subject to the award of the Production Concession, which in January 2019 was granted preliminary approval by the Italian Government, recoverable volumes can be classified as Reserves within this CPR in accordance with the requirements of AIM and the AIM Guidance Note.

As a result of a farm-in agreement between PVO and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Details of the licence are summarised below.

Table 2.1 Podere Gallina licence details

Operator	UOG Interest (%)	Status	Licence expiry date	Licence Area
PVO	20%	Exploration	3rd February 2018*	506 km^2

* In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. As soon as the decree is received, it is expected that PVO will lodge a request for the suspension of the licence for a period equal to the authorization time, in order to benefit from the full extension period. Accordingly, when awarded it is expected that the extension will be with effect from February 3, 2018. The application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities together with the development plan in May 2018. Although it has been granted preliminary approval, it does not supersede or replace the application for the exploration extension referred to above. As a result of recent changes in law in Italy, the administrative procedures related to the grant of exploration licences is currently suspended. Whilst the production licence application made by PVO in May 2018 and related award procedure are not suspended by the new law, the ultimate award of the production licence may be affected by the new law.

The report contains descriptions of the licence area, and evaluates the range of gas volumes that could be present in the identified assets and the associated risk factors.

2.1 Sources of Information

In completing this evaluation, CGG have reviewed information and interpretations provided by UOG, as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR included:-

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data
- AFE's and budgets
- Well logs (Podere Maiar well)
- Well testing reports (Podere Maiar well, latest interpretations)
- Contents of Field Development Plan dated May 2018

In conducting their evaluation, CGG have accepted the accuracy and completeness of information supplied by UOG, and have not performed any new interpretations, simulations or studies.

As the assets in question are still to be developed, no site visits have been conducted by CGG.

2.2 Evaluation methodology

In estimating the reserves and resource volumes, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Resource ranges (low, mid and high cases) have been determined using deterministic methods.

PVO staff demonstrated and reviewed the seismic workstation interpretations during a CGG visit to PVO in 2013. At the same time, maps and geological issues were discussed face to face with senior PVO staff. The seismic picks, reservoir structure and gross rock volume, according to these interpretations, was demonstrated to CGG. PVO interpretations have not changed since that time. Estimates of reservoir properties have been checked by CGG, and these are thought to be reasonable.

2.3 Principal contributors

The following personnel were involved in the drafting of the CPR.

Andrew Webb

Mr Andrew Webb has supervised the preparation of this CPR. He is the Manager of the Petroleum Reservoir & Economics Group at CGG, having joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisition and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Dr. Arthur Satterley

Has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 20 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces including onshore northern and southern Italy.

Toni Uwaga

Has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has several technical papers, published by GSTT and SPE.

Peter Wright

Has an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

2.4 Requirements

In accordance with UOG's instructions, CGG confirm that:

- CGG personnel working on this CPR are professionally qualified and members in good standing of self-regulating organisations of engineers and/or geoscientists as appropriate;
- CGG personnel working on this CPR have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;
- CGG are independent of UOG "the Company", its directors, senior management and advisers;
- CGG will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of the Company;

- CGG are not a sole practitioner;
- CGG have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

2.5 Consent

CGG hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;
- the filing of this report with any stock exchange and other regulatory authority;
- the electronic publication of this report on websites accessible by the public, including a website of the Company; and
- the inclusion of CGG's name in documents prepared in connection to commercial or financial activities.

3 GEOPHYSICS AND GEOLOGY

The Exploration Licence that is the subject of this report is located in the Po Valley onshore northern Italy. The Po Valley runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years.

3.1 Regional Context

The Po Basin is a major hydrocarbon province which was estimated by the US Geological Survey to have approximately 16 TCF of ultimately recoverable gas (Lindquist, USGS, 1999, on-line review paper). The basin occurs on the margins of the Alpine mountain chain to the North and the Apennine chain to the South. The basin opens into the Adriatic Sea to the East. Compression associated with the building of these mountain belts created a large deep basin (or "foredeep") into which large thicknesses of sediment were shed from the surrounding uplands. As the basin deepened, turbidite sands were created and the high sediment supply began to fill the basin. Many of these turbidite sands are now gas-bearing, including long-established reservoirs discovered and developed by ENI, as well as thin-bedded reservoirs that are becoming new targets at the present time. Pliocene reservoirs include marine sands of significant lateral extent, which are folded over faulted structures that were formed during the compressional phases. At least 6km of Pliocene sediments were deposited in the foredeep, and as this was filled, the Po River drainage system became established, depositing marine sands in a delta-front environment. These may be overlain by fluvial sands as subsidence slowed and the basin filled.

The source of the gas is Miocene and Pliocene shales that are interbedded with turbidites and other sediments; the gas is predominantly biogenic rather than associated with deep burial of the shales. Biogenic gas may be generated at shallower depths than is required for the generation of gas by burial, and is related to the activity of bacteria acting on organic matter buried with the shales. However, the deepest known bacterial gas generation is recorded in the Po Basin at a depth of 4500 metres. As such, the process can generate large gas volumes throughout a basin, and the source may continue to be active at the present time. These aspects have led directly to the hydrocarbon richness of the Po Basin. Many structures and many reservoirs have proven to be gas-bearing, which explains the 263 developed fields in the Po Basin. Much potential for new discoveries remains, as do many opportunities for field re-development (missed pays and remaining gas in old fields).

The assets under consideration here include Miocene and Pliocene reservoir sands, stacked vertically, and including both thick, good quality gas sands and thin-bedded gas reservoirs. Reservoir sands are interbedded with shaley and marly fine-grained sediments. In many cases, the sands are pressure isolated from each other and may be drained in succession according to well designs and completion strategies employed.

3.2 Selva Stratigraphic Reserves

The Selva Stratigraphic redevelopment opportunity represents a part of the former ENI-operated Selva gas field. The extension of the Selva Field into the Podere Gallina Licence was interpreted by Po Valley Energy Ltd. mainly using isopach mapping from well data at Upper Mid Pliocene level. Recent modelling (DREAM 2013) was based on the conservative assumption that the initial GWC of the Selva Field at 1336m TVDSS had risen to 1235m (top level C in the Selva-6 well) leaving a potential undrained updip gas volume.

Seismic and well data show the Selva Stratigraphic redevelopment to be an Upper Middle Pliocene onlap to a Lower Pliocene thrust-bounded anticline. However, interpretation of seismic lines suggests the reservoir is also displaced by reactivated thrust splays which detach onto the main thrust fault. Although the depth structure map is quite well constrained by existing well penetrations, the 2D seismic (in terms of line spacing and vintage) is imperfect for imaging small features and part of the Operator’s plan is to revise the structure mapping using additional data in the near future. The Podere Maiar-1 well was drilled in late 2017 and tested in early 2018. It targeted the updip volume based upon a new interpretation of the position of the lapout edge towards the Selva-3 well. The latest interpretation of the well test and its implications are fully incorporated into this CPR and into CGG’s consideration of Reserves.

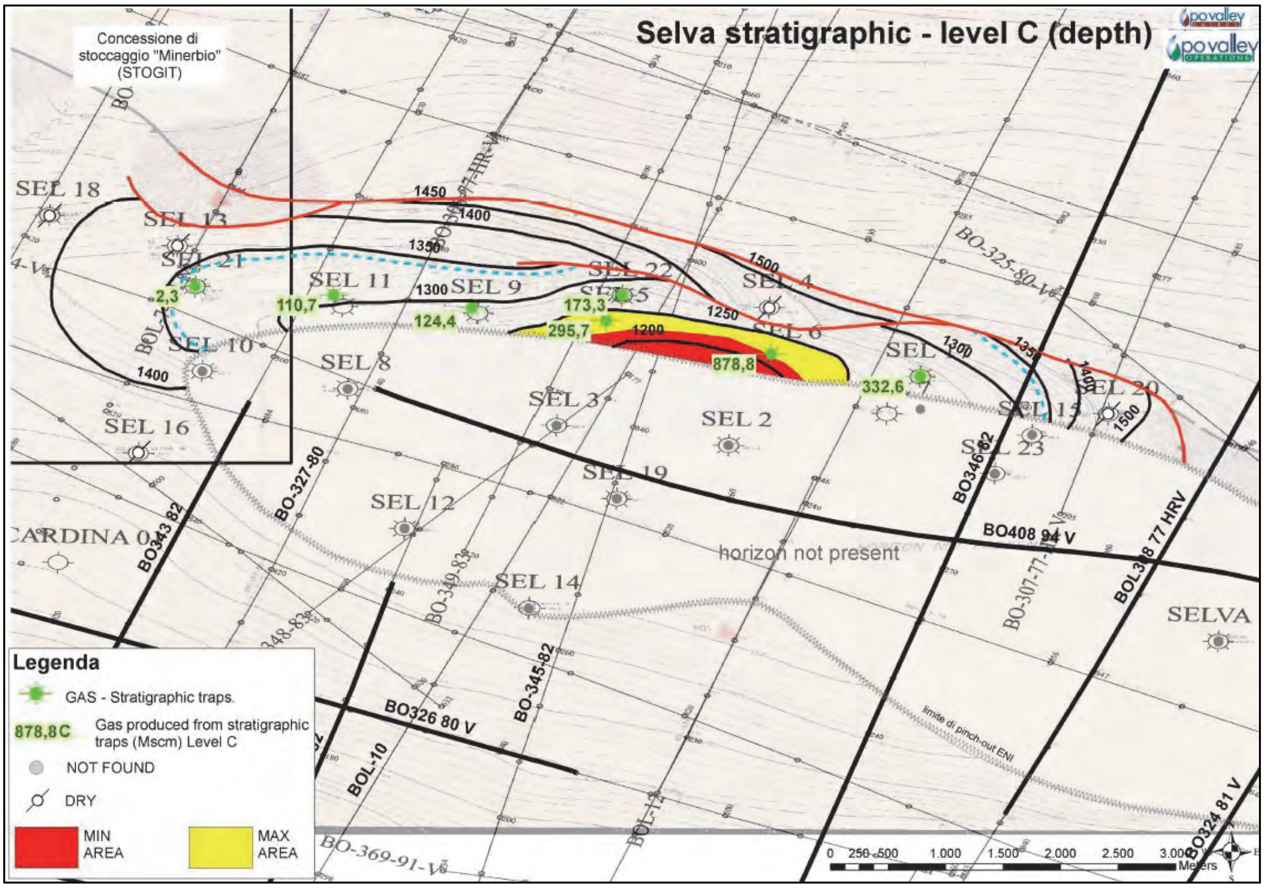


Figure 3.1 Selva stratigraphic structure map

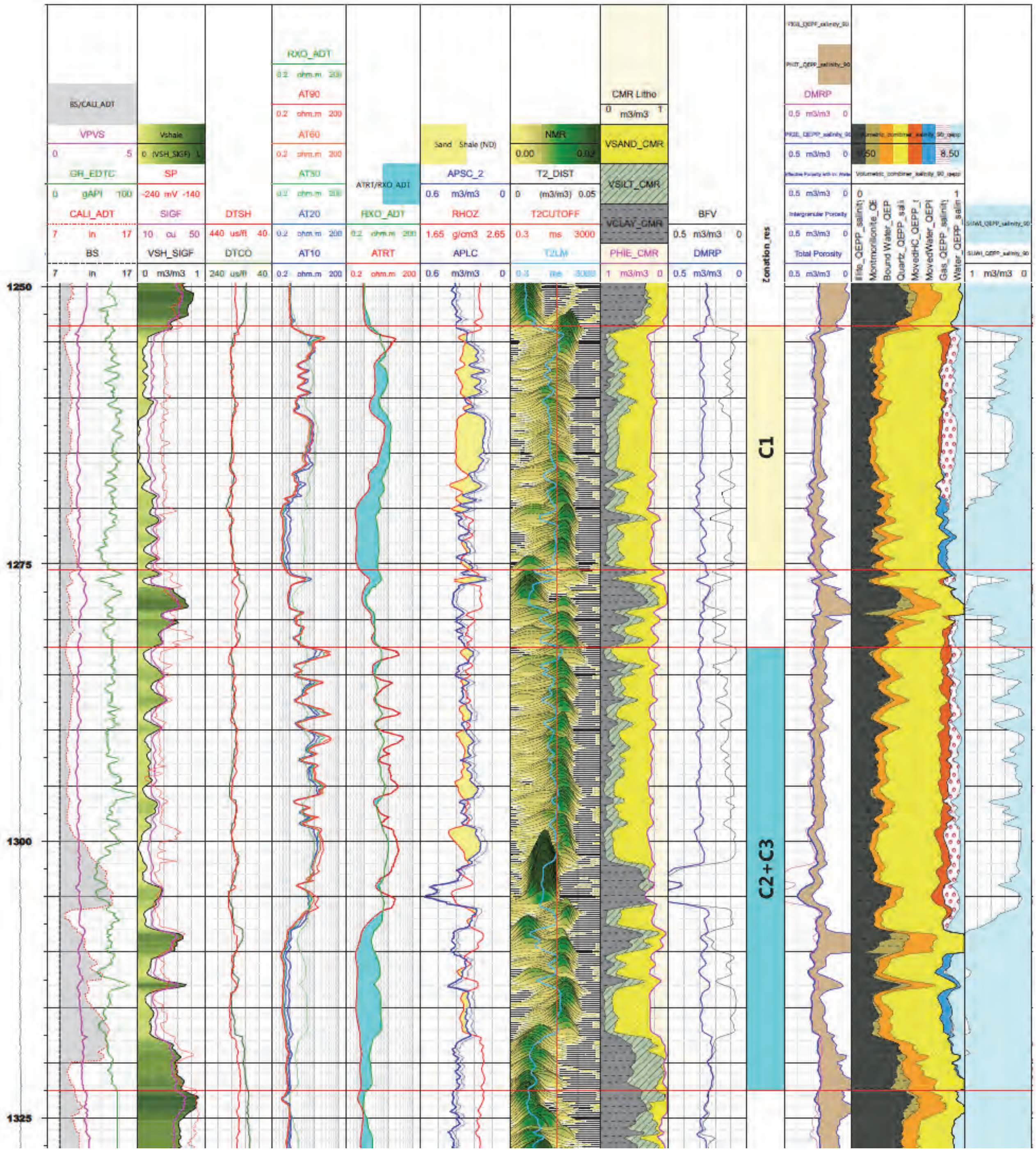


Figure 3.2 Podere Maiar-1: C1 and C2 Sand Reservoirs, Extract from ELAN Interpretation Plot

The ELAN log and interpretation plot is provided as Figure 3.2, above.

Podere Maiar-1 penetrated a gross thickness of 62.5 metres of Lower Pliocene (C1 and C2) gas sands of the old Selva field. Petrophysical analysis has indicated average properties in each sand as follows:

C1 Sand

22 metres gross thickness, 70% net-to-gross, 22-26% porosity and 65% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 case.

C2 Sand

40.5 metres gross thickness, 63% net-to-gross, 21-25% porosity and 70% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 cases.

The logging tools deployed for the assessment of the reservoirs were high quality and comprehensive, including a CMR (Figure 3.2). Porosity estimation is considered reliable as the CMR-Density technique was used (ideal for gas-filled shaly sandstones), and the CMR also clearly distinguishes sand from shale. The ELAN interpretation has been checked and appears to be reliable, showing long reservoir sections with good gas saturations. The quality of the reservoir section encountered by the well appears good and reliably defined.

Pressure data taken over the reservoir section has established a separate gas-water-contact in C1 and C2 sands which are separated by a shale. In both sands, the contact derived from pressure data points falls close to the GWC identified on the petrophysical interpretation plot. The location of the water, therefore, is quite well established from independent evidence.

Gas initially in place estimates have been reviewed and the following parameters are considered fair estimates:

Table 3.1 Parameters used in the estimation of gas-initially-in-place (GIIP)

Sand	Case	GWC	NtG	Phi	Sg	Bg	GIIP (MMscm)
C1	min	1,237.0	0.66	0.22	0.65	140	81
C1	max	1,239.6	0.75	0.26	0.65	144	299
C2	min	1,274.5	0.58	0.21	0.7	140	261
C2	max	1,277.8	0.68	0.25	0.7	144	910
Total	min						342
	max						1,208

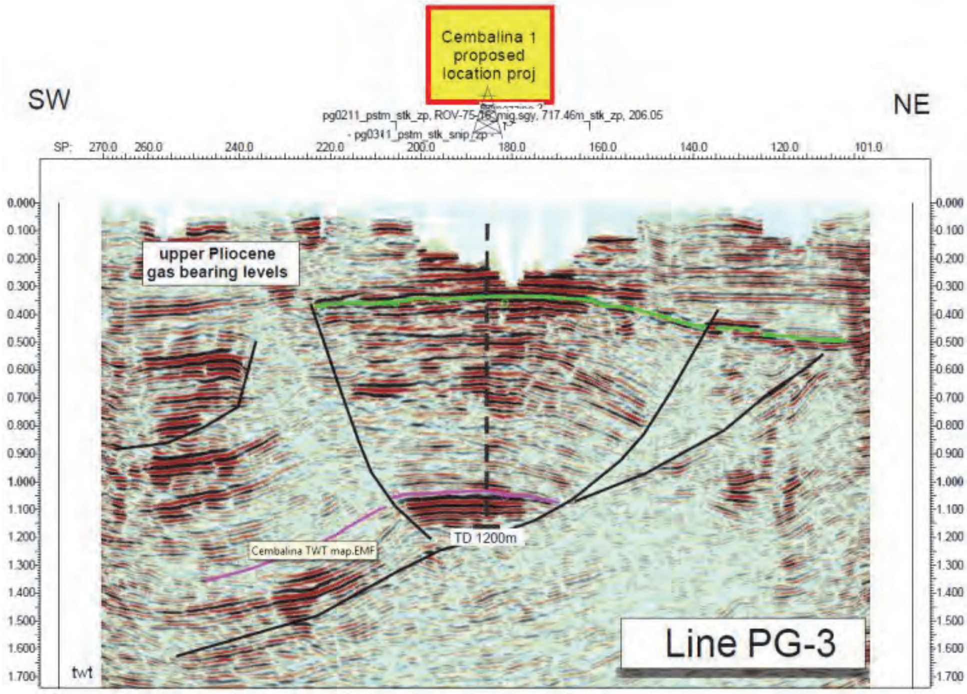
The mid-case GIIP is taken as the average of low and high.

As a proposed re-development of an old field, this appears relatively low risk; the major geological risk component is the location of the reservoir zero thickness line (pinch-out) and the shape of the pinch-out as drawn on the structure map (currently the zero line is drawn as a smooth, straight line which could be correct or could be substantially incorrect). Lack of high-resolution structural definition means Gross Rock Volume remains the greatest geological uncertainty. At this stage, post appraisal well but prior to production start-up, there is remaining uncertainty regarding the interpretation of the well test, in particular the meaning and significance of the “boundaries” seen in C1 and C2 sands. These boundaries are the result of non-unique interpretations of well test data, although the slope of the derivative is a clear reservoir signature for both sands. At the present time, CGG considers that the derivative signature from the C2 sand flow test may be significant in terms of a geological feature that limits the contacted gas volume or accelerates water coning. The major risk to recoverable gas volumes is considered to be the timing of water breakthrough. In the Po Valley region, accurately predicting the timing of water breakthrough in comparable reservoirs has been a source of uncertainty in the past. The well test and production risks will be discussed in Chapter 4.

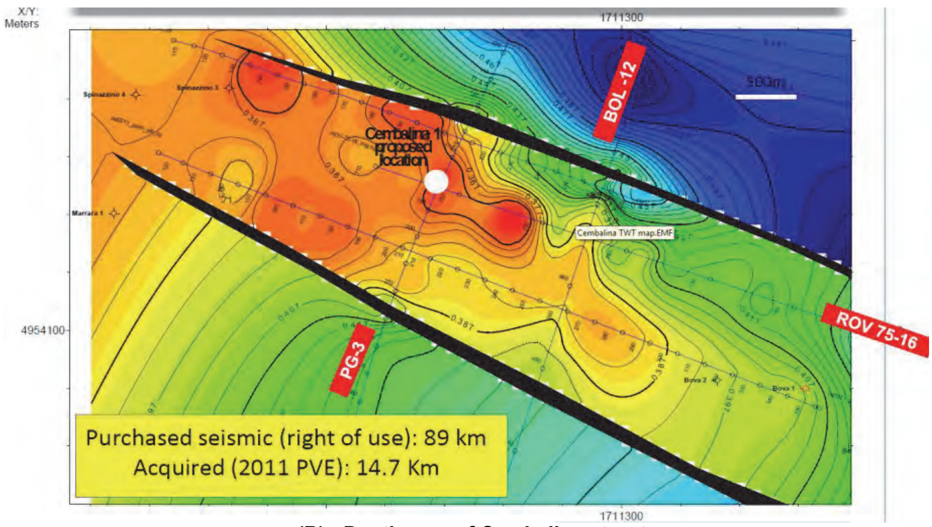
3.3 Cembalina Prospective Resource

The Cembalina prospect is defined on five seismic lines at Upper Pliocene level. Lines are oriented NNE-SSW 1.2km to 3.4km apart and WNW-ESE 0.4km to 7km apart. The structure is a WNW-ESE oriented hanging-wall anticline with associated back thrust at Early Pliocene level with fold drape above the structure at Upper Pliocene level. The seismic interpretation of horizons has been checked and validated.

Additional seismic lines purchased by PVO in 2011 resulted in a revised structural interpretation which had the effect of increasing the size of the Cembalina prospect as compared to pre 2011.



(A) Cross-section through Cembalina structure



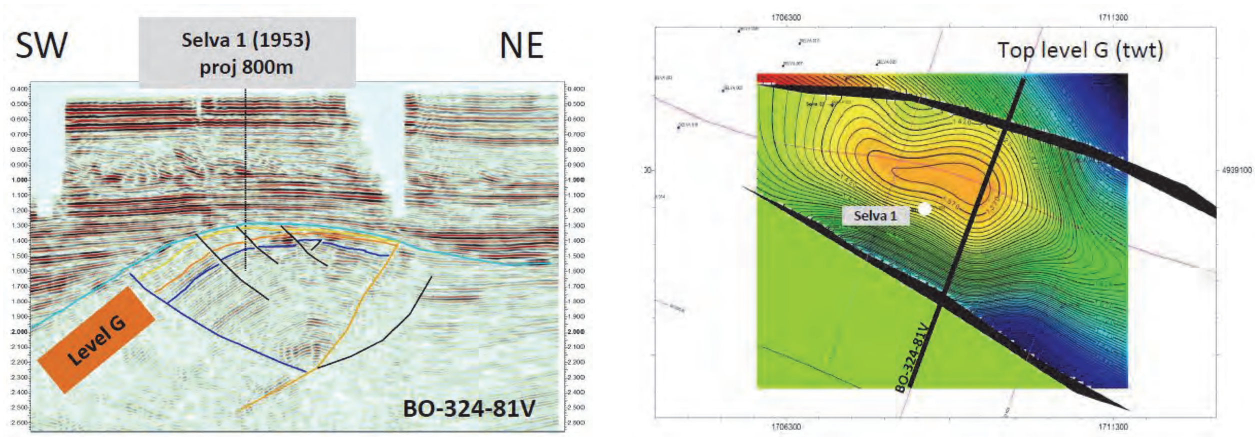
(B) Depth map of Cembalina structure

Figure 3.3 Cembalina structure

Prospective reservoirs are the Early Pliocene marine sands which, in nearby wells, exhibit up to 30% porosity with 70% average gas saturation. The thickness of these sands is expected to be about 20 metres with a net-to-gross of about 50%. In a success case, then, we concur with the prospective resource estimates given by PVO. These are a P90 of 60 MMscm, a P50 of 94 MMscm and a P10 of 133 Mscm. The CoS relating to these resources is 51% due to the proximity of gas fields producing from these Early Pliocene sands.

3.4 Fondo Perino Prospective Resource

The Fondo Perino prospect is the dip closed cap of a hanging-wall anticline located between the Selva-1 and Selva-23 wells. The trap is interpreted on two NNE-SSW oriented seismic lines located 1.3km apart and a WNW-ESE line. The limits of the prospect closure exist between smaller faults in the core of the anticline.



(A) Fondo Perino seismic cross-section (B) Fondo Perino depth structure map

Figure 3.4 Fondo Perino structure

The reservoirs are Lower Pliocene sandstones of the Selva gas field; the prospect is the updip gas bearing level tested on Selva-1 well. The CoS is good at 34% for prospective resources of 289, 413 and 581 MMscm at P90, 50 and P10 cases respectively.

3.5 East Selva Prospective Resource

The East Selva structure is identical in concept in the Selva Stratigraphic structure but has not previously been drilled. PVO reinterpreted the mapped closure area of this structure using available seismic data and CGG review of this work indicates that it presents a fair and reasonable view of the prospect.

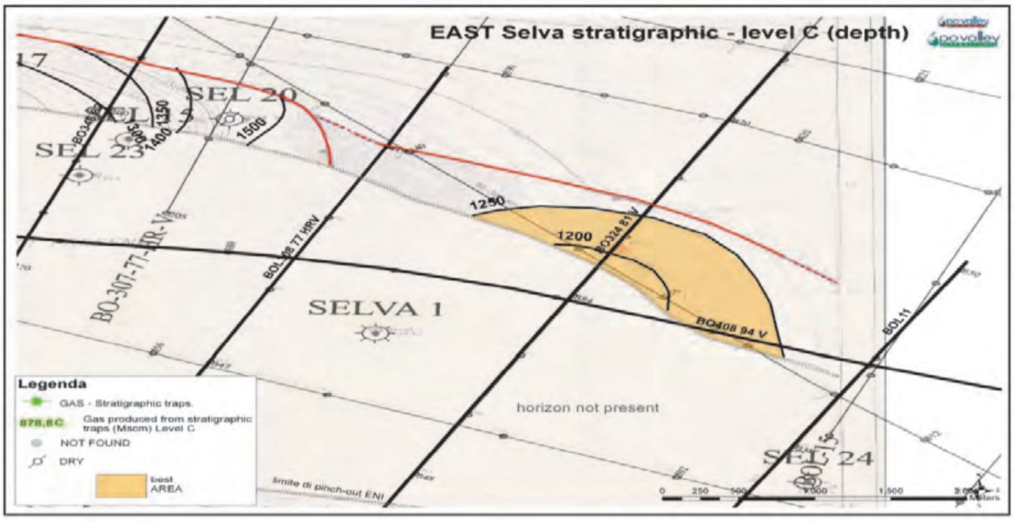


Figure 3.5 East Selva structure map

The East Selva reservoirs are expected to be as good as those in the Selva field itself. CGG's review of the Operator's work has concluded that the stated prospective resources are very reasonable. Given the proof of concept demonstrated by the success of the Podere Maiar-1 well, the Chance of Success at East Selva has been upgraded. The prospect could hold recoverable resources of 824, 986 and 1150 MMscm in Low, Best and High cases respectively for a CoS of 30%. The primary risk is the definition of the gross rock volume based on only a small number of seismic lines.

Table 3.2 Summary of Gas Prospective Resource by Prospect (MMscm)

	Gross (MMscm)			Net (MMscm)		
Prospect	**Low**	**Best**	**High**	**Low**	**Best**	**High**
Cembalina	59.5	93.5	133.1	11.9	18.7	26.6
Fondo Perino	288.9	413.5	580.6	57.8	82.7	116.1
East Selva	824.1	985.6	1149.8	164.8	197.1	230.0

4 RESERVOIR ENGINEERING

4.1 Selva Stratigraphic Trap

4.1.1 Historical production of the Selva Gas Field

The Selva gas field was previously on production during the 1950s-1980s. Total historical production from the C level is shown in Table 4.1 below:

Table 4.1 Summary of Total Gas Recovered from Selva Stratigraphic Trap (MMscm)

Well	Total Gas Recovered, MMscm
Selva-5-C	295.74
Selva-6-C	878.80
Selva-9-C	124.38
Selva-11-C	124.05
Selva-17-C	332.58
Selva-21-C	2.31
Selva-22-C	173.33
Total	**1,931.19**

Figure 4.1 shows the total gas produced from each historical well. CGG has no records of perforation intervals of Level C, only well tops. Therefore, we consider "height of sand top above Gas-Water Contact (GWC)". The height above contact of each historical well is as follows:

- Selva-21 was watered-out when GWC was at ~1,340 mTVDss, assuming this is the original water contact
- Selva-11's Top C is at 1,315 mTVDss, 25 m above contact. Produced 124 MMscm
- Selva-9's Top C is at 1,296 mTVDss, 44 m above contact. Produced 124 MMscm
- Selva-22's Top C is at 1,295 mTVDss, 45 m above contact. Produced 173 MMscm
- Selva-17's Top C is at 1,281 mTVDss, 59 m above contact. Produced 333 MMscm
- Selva-5's Top C is at 1,246 mTVDss, 94 m above contact. Produced 296 MMscm
- Selva-6's Top C is at 1,235 mTVDss, 105 m from the contact. Produced 879 MMscm

CGG postulates that the PM-1dir well will perform within the range of the posted cumulative produced gas values at historical wells. We consider that height of perforations above water is a key indicator of when water breaks through.

- In the C1 sand, PM-1's GWC is estimated at 1239 mTVDss; PM-1's Top C1 is at 1222 mTVDss, that is, 17 m above contact.
- In the C2 sand, PM-1's GWC is estimated at 1278 mTVDss; PM-1's Top C2 is at 1251 mTVDss which is 27 m above contact.

Therefore, the most closely analogous wells are Selva-11 (124 MMscm cumulative), Selva-9 (124 MMscm) and Selva-22 (173 MMscm). The PM-1dir well could perform as well as Selva-5 (296 MMscm) and Selva-17 (333 MMscm). In the high case, the PM-1dir could possibly produce as much as Selva-6 (879 MMscm cumulative). On the basis that the new well is closer to the water than most Selva wells on the map prior to the well being put on production, and there being some production history, we do not expect PM-1dir to out-perform these prior to suffering water breakthrough.

It is based on these historic production histories that the reserves volumes for the PM-1dir have been bench marked against.

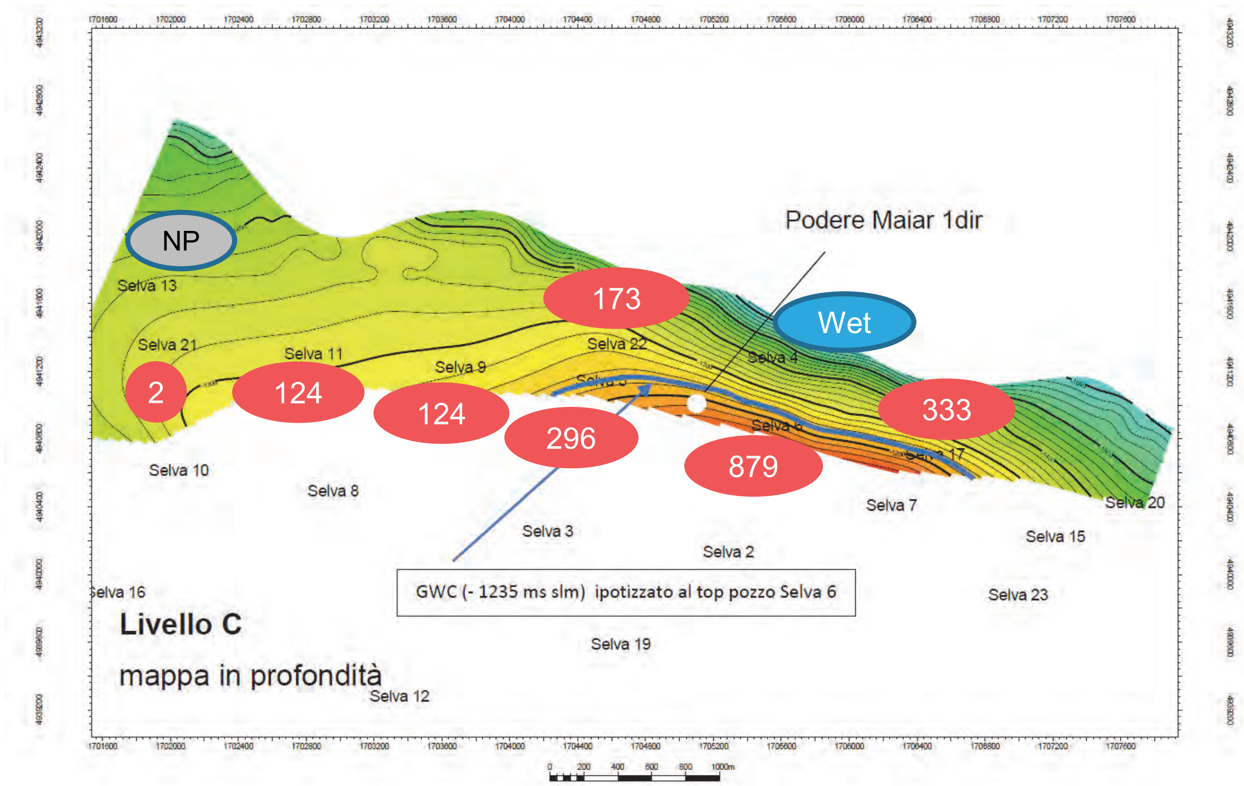


Figure 4.1 Historical Well Locations in Selva Stratigraphic Trap and Well Total Gas Production in MMscm

4.1.2 Podere Maiar-1dir well test results

Podere Maiar-1 was drilled targeting remaining updip gas of the C Level in the Selva Stratigraphic Trap. The new pressure data taken over the C level has established a separate GWC in C1 and C2 sands. In both C1 and C2 sands, the GWC has been identified. The depths of C1 and C2 sands are tabulated in Table 4.2. The bottom perforation is over 13 m above the contact.

Table 4.2 Podere Maiar-1dir – Depths of C1 and C2 Sands

Podere Maiar-1dir (RT 22.71 m)		
C1	Top, m MD RT (m SSL)	1253.5 (1221.9)
	Bottom, m MD RT (m SSL)	1275.5 (1244.4)
	GWC, m MD RT (m SSL)	1270.5 (1239)
	Perforation, m MD RT	1253.5-1256
C2	Top, m MD RT (m SSL)	1282.5 (1251)
	Bottom, m MD RT (m SSL)	1318.5 (1286.5)
	GWC, m MD RT (m SSL)	1309.5 (1277.8)
	Perforation, m MD RT	1282.5-1296

The well has been completed by a conventional completion with sliding side door (see Figure 4.2). Each sand can produce individually or co-mingle.

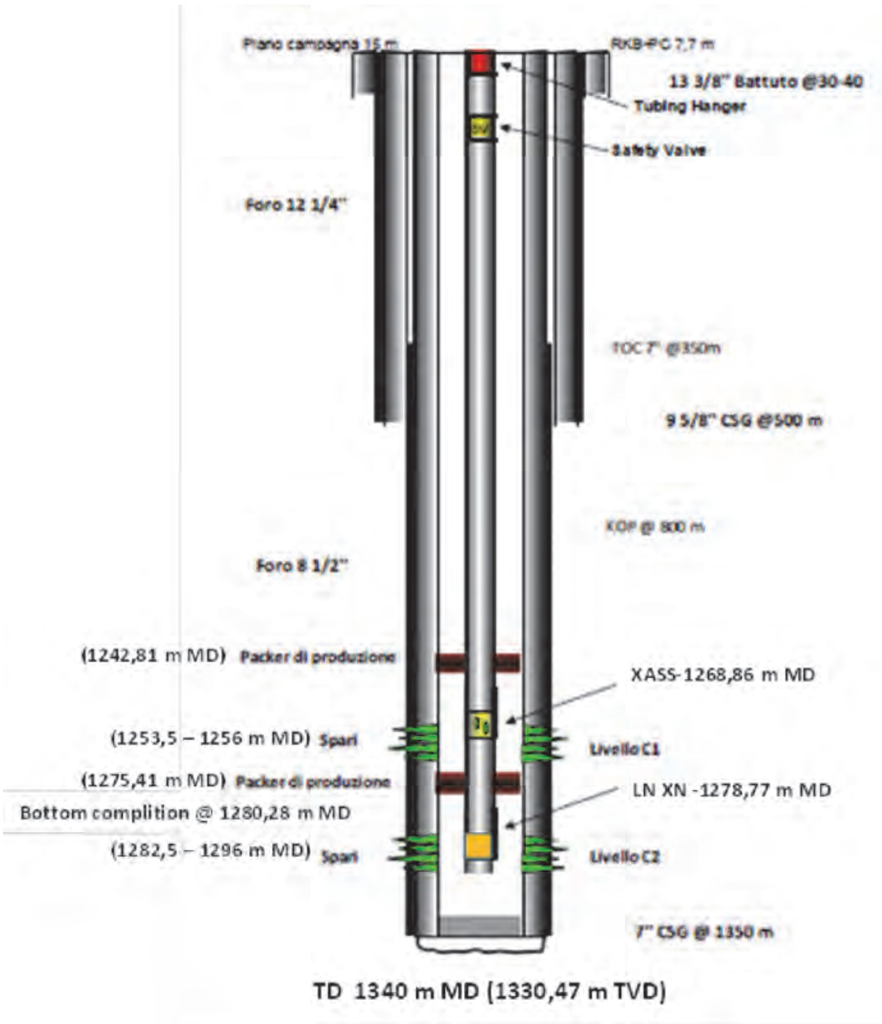


Figure 4.2 Podere Maiar-1dir – Well Schematic

The initial flow test performed in January 2018 by testing each sand individually indicates good initial gas flow rates as shown below. Although both sands have high well deliverability, the perforations of the Podere Maiar 1dir well are sited at over 13 m above the gas-water-contacts encountered in both the C1 and C2 reservoirs. An appropriate production flow rate will be required to prevent water coning and early breakthrough into the well.

Table 4.3 Summary of Flow Test Results of C1 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 132.9 bara at 1253.5 m MD RT, STHP 120.7 bara			
8	119.3	14,300	6
16	115.0	64,000	6
18	113.2	77,400	6
Build up			30
24	105.0	127,000	3
Build up			1

Table 4.4 Summary of Flow Test Results of C2 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 135.5 bara at 1275 m MD RT, STHP 122.9 bara			
8	122.7	17,800	6
16	120.7	64,800	6
18	119.5	78,000	6
Build up			50
24	104.6	142,000	4
Build up			6

The build-up tests have been interpreted by Po Valley's consultant (DREAM, Dedicated Reservoir Engineering And Management, based in Torino). Figure 4.3 to Figure 4.8, Table 4.5, and Table 4.6 are extracted from DREAM's interpretation in the submission document to the Italian authorities.

C1 sand's well test interpretation indicates that the well sees two no-flow boundaries. In Figure 4.3 during the late time i.e. after 3 hours, the pressure derivative shows positive slope indicating no-flow behaviour. In this case, DREAM interprets it as two parallel no-flow boundaries. CGG accepts DREAM interpretation of the C1 sand. The two no-flow boundaries can be interpreted as the pinch-out (South) and the structural closure (North). Pressure builds up to the pre-test pressure suggesting that the well has some pressure support and good connectivity. CGG therefore considers that the Podere Maiar-1dir is capable of draining the whole area of the updip gas.

For the C2 sand, DREAM interprets the well test as three boundaries and mentions that one of the boundaries might be the aquifer. In Figure 4.6, during the late time (i.e. after 1 hour), the pressure derivative starts to divert from radial flow (zero slope) to slightly positive slope and the pressure derivative continues to show positive slope indicating no-flow behaviour. The boundaries could be leaking, although we have not observed this during the short test. This could not be an aquifer effect as the derivative of pressure would have shown a negative slope in the late time. We agree with DREAM that the C2 sand has encountered three boundaries. Two of the boundaries are no-flow and can be interpreted as the pinch-out (South) and the structural closure (North). The shortest boundary, at a distance of 80 m, could indicate that there is a boundary that could not be seen in the existing seismic data. However, the well test data does not identify if the boundary at 80 m is to the East or the West of the well. The hypothesis of a third boundary is supported by the fact that the final build-up reservoir pressure that does not reach the pre-test value. This may indicate some depletion of a limited connected gas volume. Although the pressure loss during the test is very small (1/10th bar after 50 hours of shut-in), the pressure did not build-up back to the pre-test value as observed in C1 (in which the pressure returned to the pre-test value after 30 hours of shut-in, as we would expect in high quality reservoir with a longer shut-in time). CGG therefore has taken into consideration that the Podere Maiar-1dir well may only drain a limited area of the updip gas and assigns only 44% (considering the boundary is located to the West of the well) of the total drainage area of the low in-place volumes in the 1P reserves. For the 2P reserves, only 63% (considering the boundary is located to the East of the well) of the total drainage area of the mid in-place volumes is assigned. However, the 80 m no-flow boundary may not fully seal (i.e. leaking) and the whole area could possibly be drained by the Podere Maiar-1dir well. We therefore assign 100% of the high drainage area in our 3P reserves.

For the C2 sand, CGG recognises that the three no-flow boundaries interpretation may not be a unique solution. Alternative interpretations are possible. This has been taken into consideration of our reserves uncertainty i.e. 44%, 63%, and 100% drainage area.

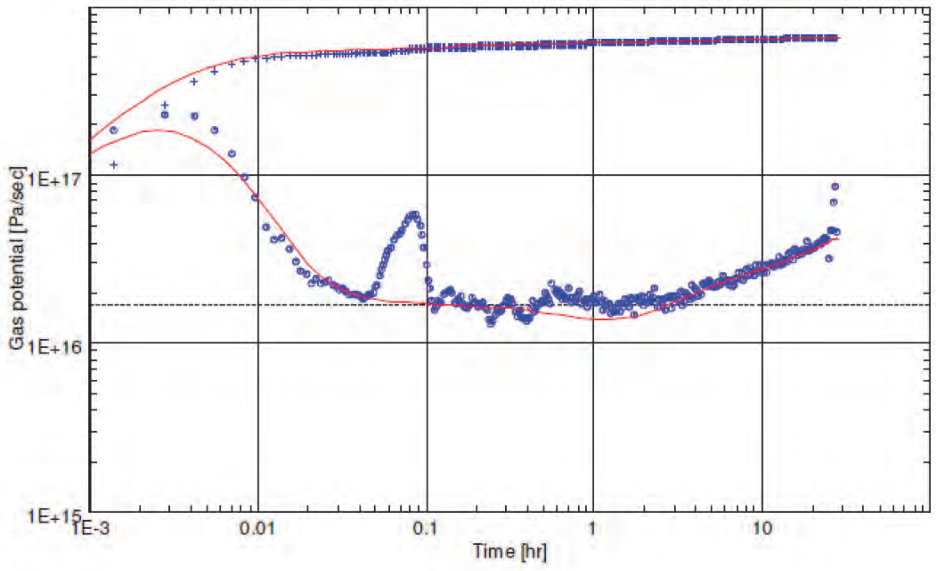


Figure 4.3 Log-log Plot of Pressure and Pressure Derivative of C1 Sand

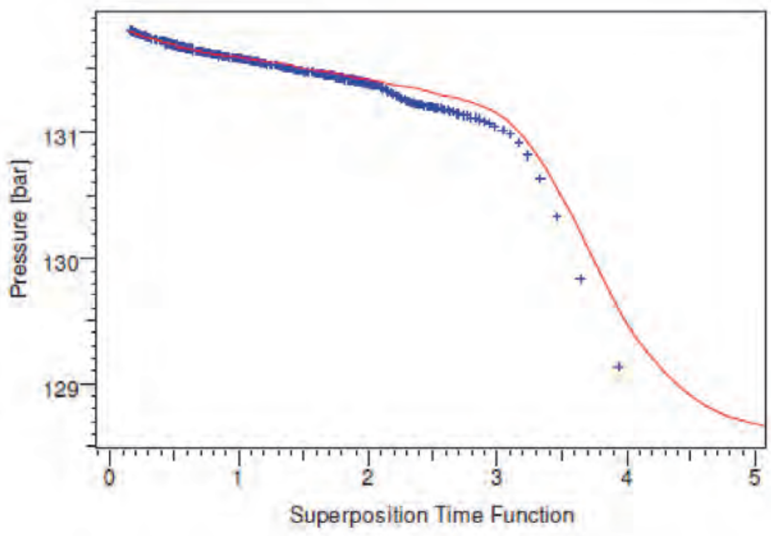


Figure 4.4 Horner Plot of C1 Sand

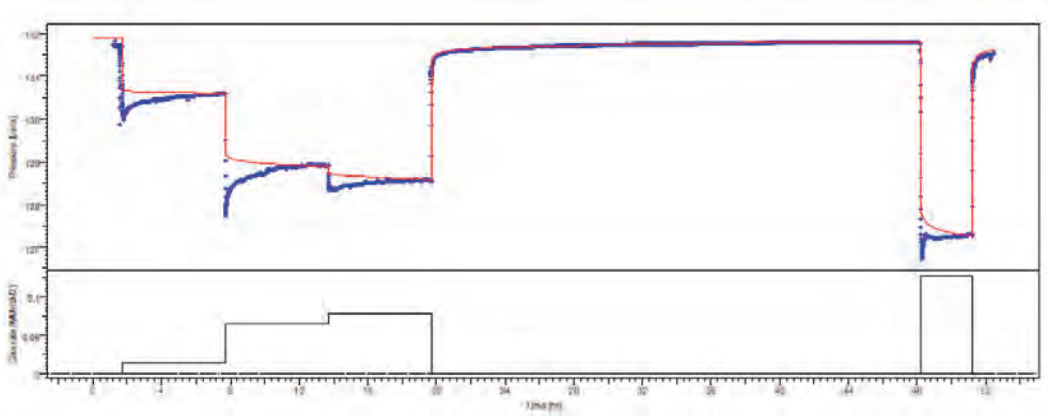


Figure 4.5 Pressure and Gas Rate of C1 Sand

Table 4.5 Well Test Interpretation Result of C1 Sand

P_i	131.9	bar
kh	949	mD m
h	2.5	m
k	380	mD
S_m	decreasing	
d1	120	m
d2	190	m

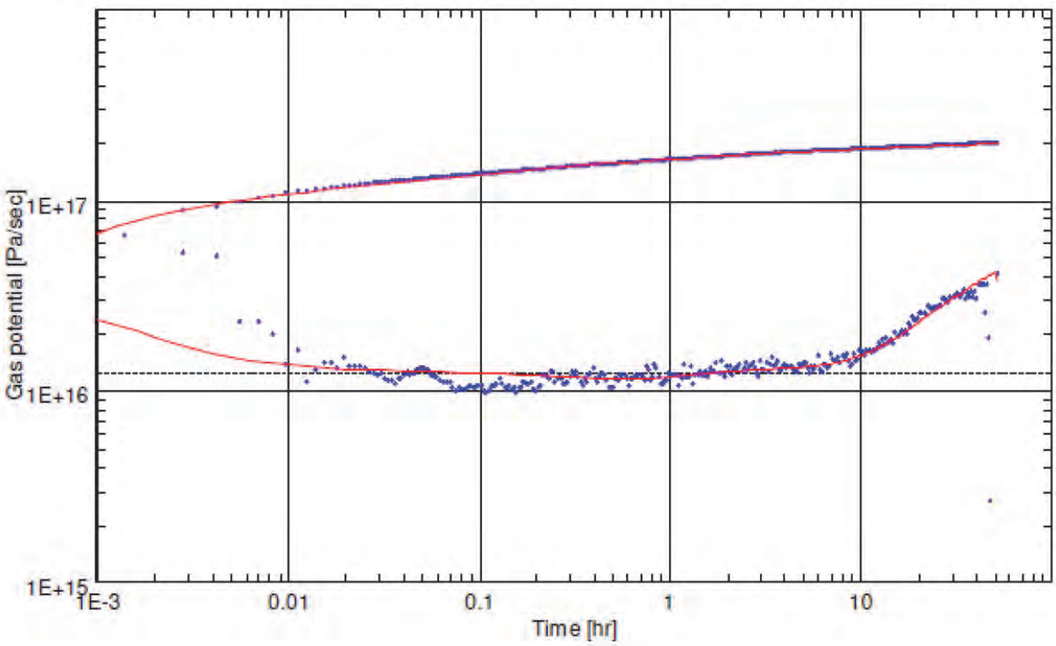


Figure 4.6 Log-log Plot of Pressure and Pressure Derivative of C2 Sand

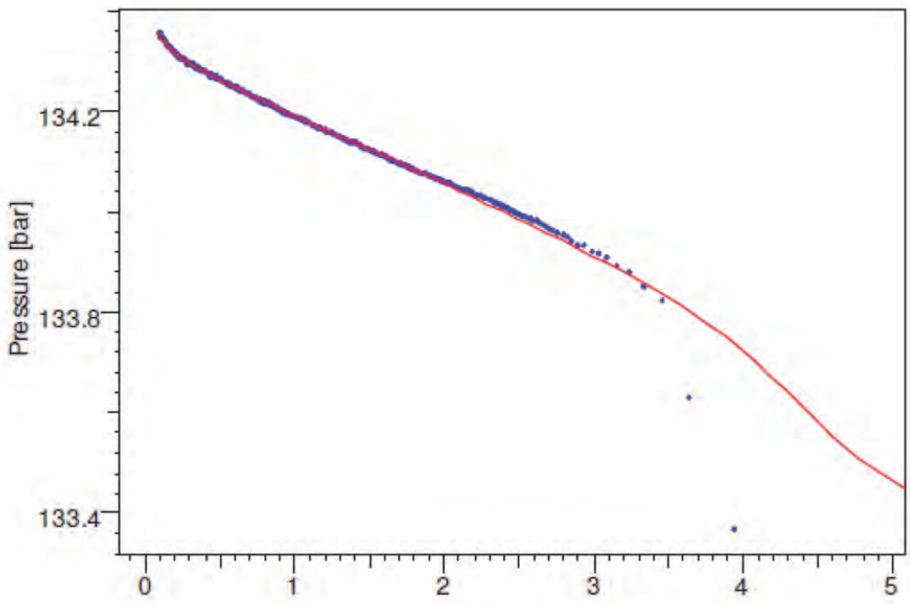


Figure 4.7 Horner Plot of C2 Sand

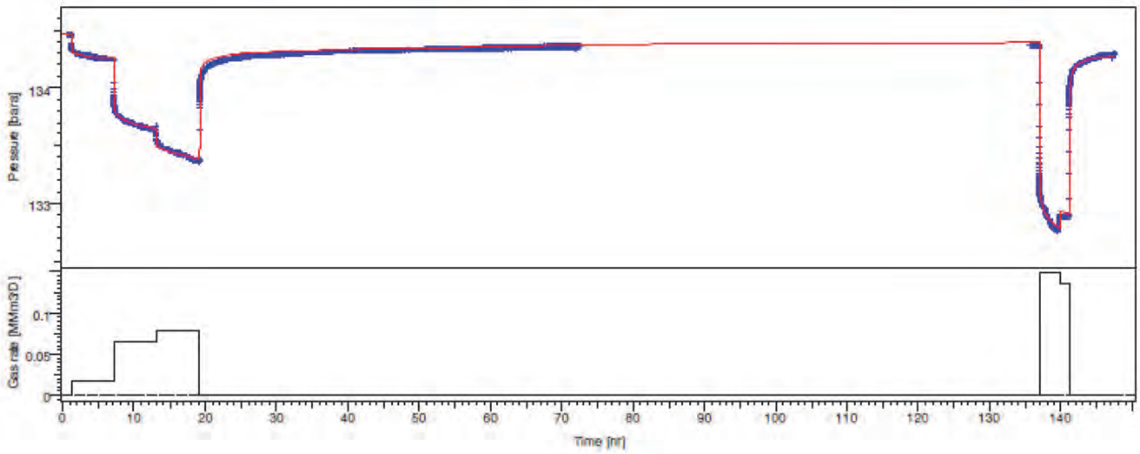


Figure 4.8 Pressure and Gas Rate of C2 Sand

Table 4.6 Well Test Interpretation Result of C2 Sand

P_i	134.5	bar
kh	1440	mD m
h	8.5	m
k	169	mD
d1	80	m
d2	120	m
d3	170	m

4.1.3 Reserves

Selva gas consists of approximately 99.5% methane and has low hydrocarbon liquids content, and as such will require minimal surface processing when the field is redeveloped. The Italian gas grid (SNAM) is also located approximately one kilometer in the South-West direction from the proposed field facilities. The field re-development plan is currently under review by the Italian authorities.

CGG has reviewed both historical well production and the Podere Maiar-1dir well test results. We have estimated 1P, 2P and 3P reserves used parameters tabulated in Table 4.7. The 1P, 2P and 3P reserves are summarized in Table 4.8.

- For 1P reserves, with low in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 44% of the area. The recovery factor of 60% is assigned for both sands.

- For 2P reserves, with mid in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 63% of the area. The recovery factor of 68% is assigned for both sands.

- For 3P reserves, with high in-place volumes, both C1 and C2 sands can drain 100% of the area. The recovery factor of 70% is assigned for both sands.

This range covers the uncertainties in the volumes, taking into consideration the uncertainty of the location and presence of “boundaries”.

Table 4.7 Summary of Parameters Used for Reserves Calculation

Sand	Case	GIIP (MMscm)	% Area Contacted by PM-1	Contacted GIIP (MMscm)	Recovery Factor (%)	Reserves (MMscm)*
C1	1P	81	100	81	60	48
	2P	190	100	190	68	129
	3P	299	100	299	70	209
C2	1P	261	44	115	60	69
	2P	585	63	369	68	250
	3P	910	100	910	70	637
Total	1P	342	N/A	195	N/A	117
	2P	775	N/A	558	N/A	379
	3P	1,208	N/A	1,208	N/A	846

** The numbers may not add due to rounding error.*

In light of the preliminary award of the Production Concession which was awarded in January 2019 by the Italian authorities, the “Selva Stratigraphic” redevelopment is clarified as reserves.

As water breakthrough is the major risk to recoverable gas volumes, PVO proposes to produce at a maximum gas rate of around 80,000 scm/day, solely from C2 sand then switch to C1 sand. In the event of earlier than expected water breakthrough, it would have a major impact on the project and as such could require an additional well.

Table 4.8 Summary of Technical Reserves for the Selva Redevelopment Project

Selva Stratigraphic Trap	Gross (MMscm)			Net (MMscm)		
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible
C1 Sand	48	129	209	10	26	42
C2 Sand	69	250	637	14	50	127
Total	**117**	**379**	**846**	**23**	**76**	**169**

**The reserves classification is subject to the award of a Production Concession.*

CGG has compared the reserves to the historical production as shown in Figure 4.9. We find the reserves are in the reasonable range of low, mid, and high historical well performance. Our 1P, 2P and 3P reserves are based on producing with the minimum WHP of 70 barg and lower to 30 barg towards the end of well life. Therefore, it is reasonable to see slightly higher 2P reserves comparing to the historic wells that were limited at 80 barg WHP.

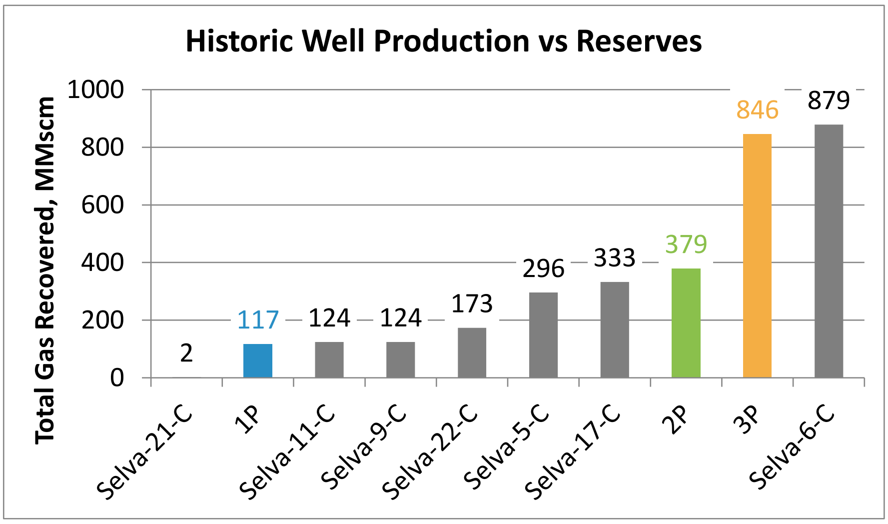


Figure 4.9 Comparison between historical production and reserves

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.10. Table 4.9 shows the annual production and cumulative production.

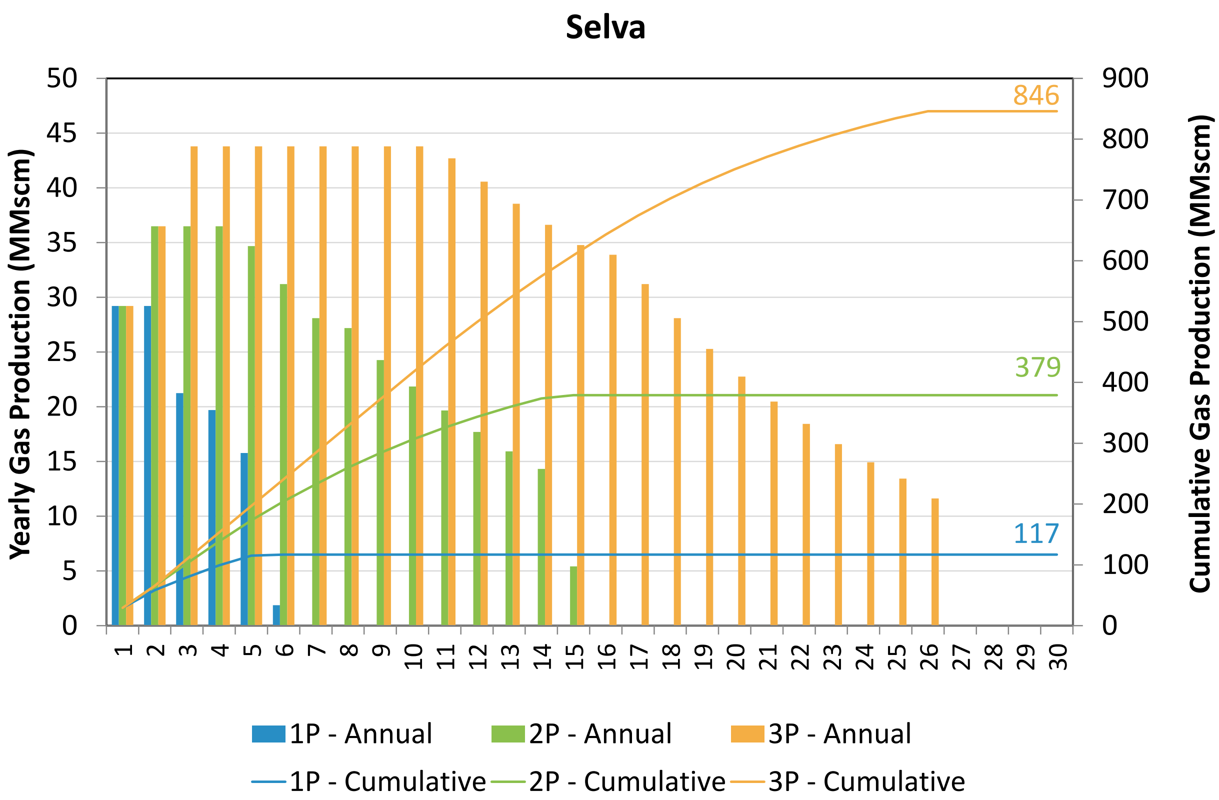


Figure 4.10 Technical Production Profiles of Selva 1P, 2P and 3P (before Economic Cut-off)

Table 4.9 Annual Production and Cumulative Production of Selva (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
1	29.20	29.20	29.20	29.20	29.20	29.20
2	29.20	58.40	36.50	65.70	36.50	65.70
3	21.25	79.65	36.50	102.20	43.80	109.50
4	19.71	99.36	36.50	138.70	43.80	153.30
5	15.77	115.12	34.68	173.38	43.80	197.10
6	1.88	117.00	31.21	204.58	43.80	240.90
7	0.00	117.00	28.09	232.67	43.80	284.70
8	0.00	117.00	27.19	259.86	43.80	328.50
9	0.00	117.00	24.27	284.13	43.80	372.30
10	0.00	117.00	21.85	305.97	43.80	416.10
11	0.00	117.00	19.66	325.63	42.71	458.81
12	0.00	117.00	17.69	343.33	40.57	499.37
13	0.00	117.00	15.93	359.25	38.54	537.92
14	0.00	117.00	14.33	373.59	36.61	574.53
15	0.00	117.00	5.41	379.00	34.78	609.31
16	0.00	117.00	0.00	379.00	33.89	643.21
17	0.00	117.00	0.00	379.00	31.21	674.41
18	0.00	117.00	0.00	379.00	28.09	702.50
19	0.00	117.00	0.00	379.00	25.28	727.78
20	0.00	117.00	0.00	379.00	22.75	750.53
21	0.00	117.00	0.00	379.00	20.48	771.00
22	0.00	117.00	0.00	379.00	18.43	789.43
23	0.00	117.00	0.00	379.00	16.58	806.02
24	0.00	117.00	0.00	379.00	14.93	820.94
25	0.00	117.00	0.00	379.00	13.43	834.38
26	0.00	117.00	0.00	379.00	11.62	846.00
27	0.00	117.00	0.00	379.00	0.00	846.00
28	0.00	117.00	0.00	379.00	0.00	846.00
29	0.00	117.00	0.00	379.00	0.00	846.00
30	0.00	117.00	0.00	379.00	0.00	846.00

4.2 Cembalina, Fondo Perino and East Selva

There are currently no firm plans to drill wells on the Cembalina, Fondo Perino or the East Selva prospects located within the licence area.

The 3D seismic that is planned across the Selva Field will also cover the East Selva and Fondo Perino prospects. It should help to de-risk these structures, and progress them towards drill-ready status.

5 ECONOMIC ANALYSIS

5.1 Methodology

Net Present Values (NPVs) have been calculated using industry standard discounted cash flow analysis. CGG have created an after-tax economic model in Excel™ for this purpose. The estimated production profiles and costs have then been input in order to calculate NPVs for each of the reserve categories.

The tax benefit of any brought forward losses and/or undepreciated capex arising from trading activities and expenditure prior to the effective date has not been included in the valuation. Corporate overhead costs not specifically allocated to the operating costs and any payments relating to the farm-in agreements have also not been included.

5.2 Assumptions

5.2.1 Gas prices

It is assumed that future gas production is sold at the Italian spot gas price – the Punto di Scambio Virtuale (PSV) price. CGG have assumed that the PSV price will follow the forward curve for the Dutch TTF spot price plus Euro 1.9/MWh, which was the average difference between the two prices in 2018. Beyond the end of the current quoted forward curve in 2025, it is further assumed that the price escalates at 2% per year. The PSV price assumption used in the economic evaluation, which is based on the TTF forward curve on 23rd November 2018, is tabulated below.

Table 5.1 PSV gas price assumption

Year	Base price (Euro/m^3)
2019	0.260
2020	0.241
2021	0.228
2022	0.220
2023	0.210
2024	0.203
2025	0.200
2026+	+2% pa

In order to capture gas price uncertainty, low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

The calorific value of gas from the field is assumed to be 38MJ/m3. No condensate production has been assumed.

5.2.2 Fiscal System

Italy's upstream oil and gas industry operates under a concessionary royalty and taxation system. Concessions are granted by the state through the National Office of Mining, Hydrocarbons and Geothermal Resources (UNMIG).

Royalty is paid on the wellhead value of production, with certain volumes exempt depending on the region and type of development. The applicable royalty rate for Selva is assumed to be 10%, with an annual royalty free allowance of 25 million cubic metres.

Profits are subject to standard Italian corporate income tax (IRES), for which the current rate is 24.0%. Tax losses can be carried forward indefinitely, and allowances are as follows:

- Exploration and Appraisal costs at 100 percent as incurred.
- Non-Well Capital costs depreciated at 15 percent, on a straight line basis (10% in the 7th year).
- Well Capital costs depreciated on a unit of production basis.
- Abandonment expenditure depreciated on a unit of production basis.
- Operating expenditure at 100 percent as incurred.
- Royalty payments at 100 percent as incurred.

In addition to IRES, companies with onshore production are also subject to a regional income tax (IRAP). The IRAP rate is assumed to be 3.9%, and is calculated in a similar way to IRES.

5.2.3 Other assumptions

The following assumptions have also been used by CGG.

Table 5.2 Economic Parameters

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost /Price Inflation	2% per annum
Discount Date	1st January 2019

5.3 Facilities and costs

The proposed development plan for Selva consists of surface processing facilities and a 1 km export pipeline to the SNAM grid. The surface facilities will include skid mounted separation and dehydration units, fiscal metering and produced water storage tanks. An allowance has also been made to add compression later in field life. The estimated development costs are as follows:

Table 5.3 Development Costs (Gross 100%)

Item	€ MM (gross)	€ MM (net)
Surface facilities	1.42	0.28
Compressor	0.23	0.05
Pipeline to grid	0.18	0.04
Project Management	0.137	0.03
Environmental	0.35	0.07
Insurance	0.023	0.00
Total	**2.339**	**0.47**

Operating costs are estimated to be approximately €0.3MM per year with an additional charge of €0.015/M^3 for compression when required.

Abandonment costs at the end of field life are estimated to be €1.363MM
The schedule to first gas from receiving a Production Concession is assumed to be 9 months, with first gas planned for early 2020.

CGG have reviewed these assumptions, which are deemed to be reasonable.

5.4 Results

NPVs are presented for the Proven, Proven plus Probable, and Proven, Probable and Possible reserve cases for a 100% field interest and respective net interests.

It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project.

Table 5.4 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	2.0	5.5	9.2	PVO
Low	7.6	21.3	36.2	1.5	4.3	7.2	
High	12.7	33.5	56.0	2.5	6.7	11.2	

Capital and operating cost sensitivities to NPV have been performed at the base gas price and are presented in the table below.

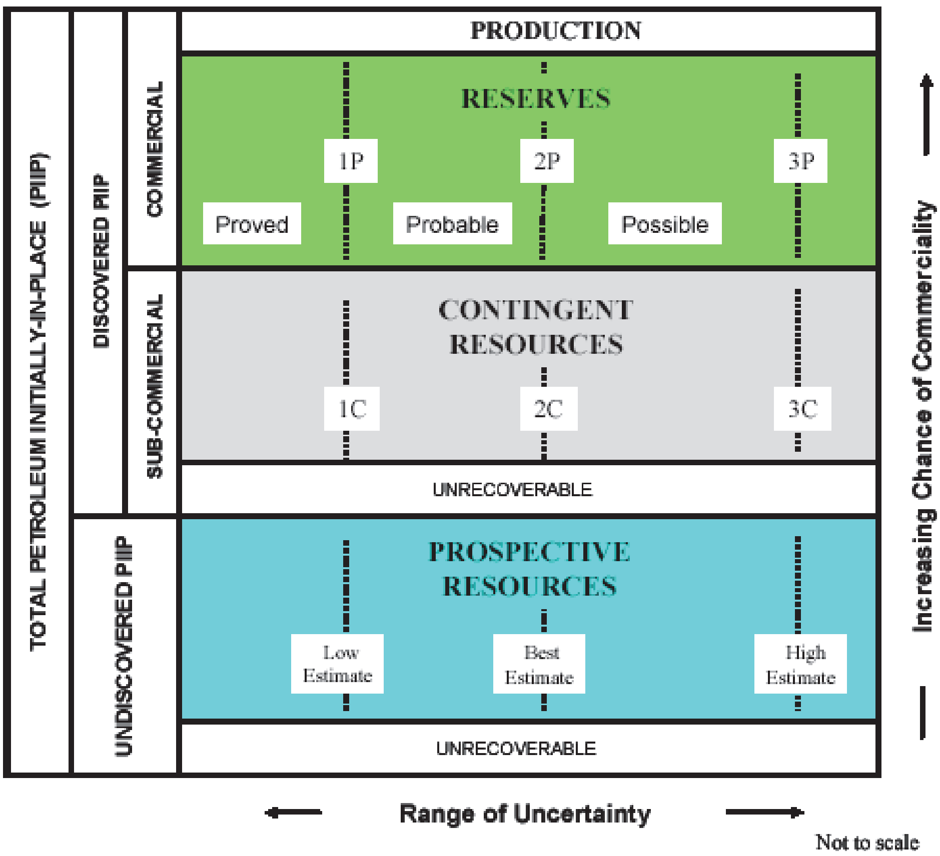
Table 5.5 NPVs cost sensitivities

Gas price	NPV10 € MM (gross)			NPV10 € MM (net)		
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible
Base	10.1	27.4	46.1	2.0	5.5	9.2
Capex +25%	9.5	26.8	45.5	1.9	5.4	9.1
Capex -15%	10.5	27.8	46.5	2.1	5.6	9.3
Opex +25%	9.8	26.8	45.4	2.0	5.4	9.1
Opex -15%	10.4	27.8	46.5	2.1	5.6	9.3

6 APPENDIX A: DEFINITIONS

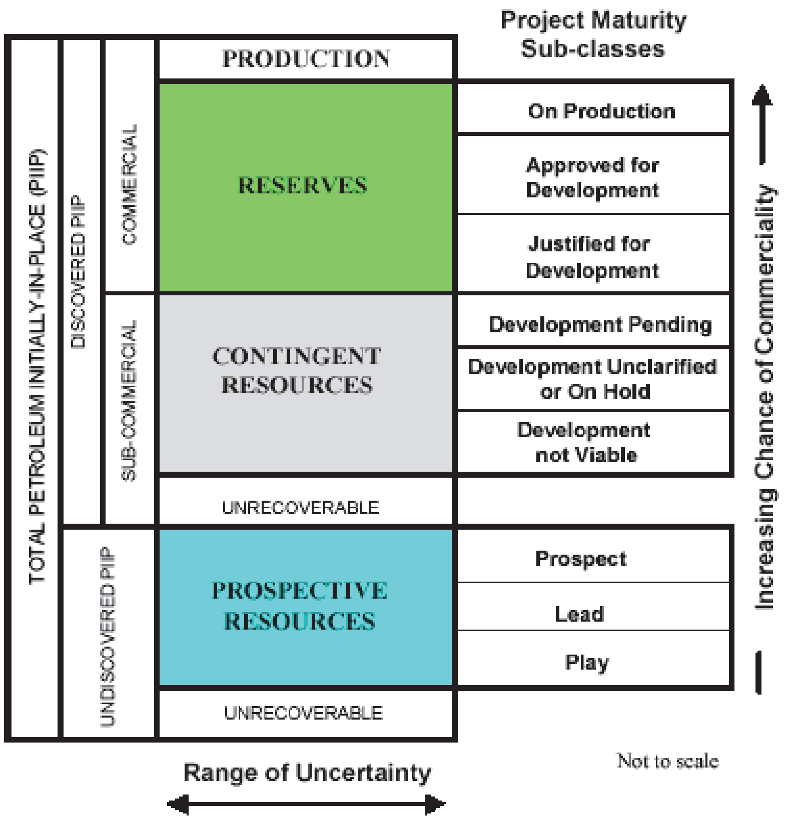
6.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented in the following sections.



Source: SPE Petroleum Resources Management System 2007

Figure 6.1 Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 6.2 Resources Classification Framework: Sub-classes based on Project Maturity

6.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

6.1.2 Discovered Petroleum Initially-In-Place

Discovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

6.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

6.2 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

6.3 Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations, from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- A project must be sufficiently defined to establish its commercial viability
- There must be a reasonable expectation that all required internal and external approvals will be forthcoming
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The “decision gate” whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

6.3.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

6.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

6.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

6.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

6.3.5 Probable Reserves

Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved + Probable Reserves (2P).

When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

6.3.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved + Probable + Possible (3P), which is equivalent to the high estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

6.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

6.4.1 Contingent Resources: Development Pending

Contingent Resources (Development Pending) are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

6.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources (Development Un-clarified / On hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

6.4.3 Contingent Resources: Development Not Viable

Contingent Resources (Development Not Viable) are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognised in the event of a major change in technology or commercial conditions.

6.5 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

6.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

6.5.2 Lead

A Lead is classified as a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

6.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

6.6 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

7 APPENDIX B: NOMENCLATURE

acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute
av.	Average
AVO	Amplitude vs. Off-Set
bbl	barrel
Bscf	billion standard cubic feet
Bscm	billion standard cubic metres
BHT	bottom hole temperature
BHP	bottom hole pressure
boe	barrel of oil equivalent
bbl/d	barrels per day
Btu	British thermal unit
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E	East
E & P	exploration & production
EAEG	European Association of Exploration Geophysicists
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
FPSO	Floating Production Storage and Offloading vessel
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IOR	improved oil recovery
IRR	internal rate of return
kg	kilogram
km	kilometre
km^2	square kilometres
kWh	kiloWatt-hours
LoF	life of field
LP	low pressure
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metre
M	thousand
MM	million
Ma	million years (before present)
Mbbl/d	thousands of barrels per day
mbdf	metres below derrick floor
mbsl	metres below sea level
Mbbl/d	thousands of barrels per day
Mscfd	thousand standard cubic feet per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz

MJ	megajoule
Mscm	thousand standard cubic metres
MMscm	million standard cubic metres
ml	millilitres
mls	miles
MMbbl	million bbls of oil
MMboe	million bbls of oil equivalent
MMscfd	million standard cubic feet per day
MMt	million tons
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
MWh	MegaWatt-hours
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
1P	proved
2P	proved + probable
3P	proved + probable + possible
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
Ø	porosity
plc	public limited company
por.	Porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
scf	standard cubic feet
scm	standard cubic metre*
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
stbbl	stock tank barrel
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
Tscf	trillion standard cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
UV	ultra-violet
VDR	virtual dataroom
W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

* 1 scm = 35.3147 scf

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PART X

DEFINITIONS

The following definitions apply throughout this Document, unless the context requires otherwise.

"£" or "UK Sterling"	Pound Sterling, the lawful currency of the UK
"Acquisition Agreement"	the conditional agreement dated 25 July 2017 between: (1) the Company; and (2) the Vendors in relation to the Acquisition, further details of which are set out in paragraph 11.30 of Part VII of this Document
"Acquisition"	the conditional acquisition by the Company of the entire issued share capital of UOG UK pursuant to the Acquisition Agreement
"Act"	the UK Companies Act 2006, as amended
"Admission"	admission of the Company's entire issued ordinary share capital to trading on AIM and such admission becoming effective in accordance with the AIM Rules
"AIM"	the market of that name operated by the London Stock Exchange
"AIM Rules" or "AIM Rules for Companies"	the AIM Rules for Companies published by the London Stock Exchange from time to time (including, without limitation, any guidance notes or statements of practice) and those other rules of the London Stock Exchange which govern the admission of securities to trading on, and the regulation of, AIM from time to time
"Assigned Interest"	an undivided legal and beneficial twenty per cent. interest in the production sharing agreement between Tullow Jamaica and the PCJ dated 16 October 2014 relating to the Walton Basin and Morant Basin consisting of blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a portion of block 1, offshore Jamaica from 1 November 2017
"Aurora"	Aurora Production (UK) Limited, a company incorporated and registered in Scotland with company number SC301743
"Baron"	Baron Oil PLC, a company incorporated and registered in England and Wales with company number 05098776
"Beaumont Cornish"	Beaumont Cornish Limited, a member of the London Stock Exchange and authorised and regulated in the conduct of investment business by the FCA
"Beaumont Cornish Warrants"	warrants created pursuant to the Beaumont Cornish Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Beaumont Cornish Warrant Instrument
"Beaumont Cornish Warrant Instrument"	the warrant instrument executed by the Company constituting the Beaumont Cornish Warrants, details of which are set out in paragraph 11.15 of Part VII of this Document
"Board"	the directors of the Company from time to time
"Bribery Act"	the Bribery Act 2010

"Cancellation"	the cancellation of admission of the Ordinary Shares to the Standard Segment of the Official List and to trading on the Main Market becoming effective in accordance with the Listing Rules and the Admission and Disclosure Standards of the London Stock Exchange
"certificated" or "in certificated form"	an Ordinary Share which is not in uncertificated form
"Change of Control"	the acquisition of Control of the Company by any person or party (or any group of persons or parties who are acting in concert)
"City Code" or "Takeover Code"	the UK City Code on Takeovers and Mergers
"Closely Associated Person"	(a) a spouse, or a partner considered to be equivalent to a spouse in accordance with national law; (b) a dependent child, in accordance with national law; (c) a relative who has shared the same household for at least one year on the date of the transaction concerned; or (d) a legal person, trust or partnership, the managerial responsibilities of which are discharged by a person discharging managerial responsibilities or by a person referred to in point (a), (b) or (c), which is directly or indirectly controlled by such a person, which is set up for the benefit of such a person, or the economic interests of which are substantially equivalent to those of such a person.
"Company" or "UOG" or "United"	United Oil & Gas Plc (formerly known as Senterra Energy plc), a company incorporated in England and Wales under the Act with company number 09624969
"Competent Person(s)"	ERC Equipoise Limited and CGG Services (UK) Limited (individually and collectively)
"Connected Persons"	has the meaning set out in section 252 of the Act and includes a spouse, children under 18 and any company in which the relevant person is interested in shares comprising at least one-fifth of the share capital of that company
"Contract"	a farmout agreement dated 24 November 2017 between Tullow Jamaica and UOG Jamaica pursuant to which Tullow Jamaica agreed to transfer the Assigned Interest to UOG Jamaica
"Control"	an interest, or interests, in Ordinary Shares carrying in aggregate 30 per cent. or more of the Voting Rights of a company, irrespective of whether such interest or interests give de facto control
"Corallian"	Corallian Energy Limited, a company incorporated and registered in England and Wales under the Act with company number 09835991
"Corallian Licences"	together, the P1918 Licence, PEDL 330 Licence and the PEDL 345 Licence
"Corfe"	Corfe Energy Limited, a company incorporated and registered in England and Wales under the Act with company number 06030678
"CREST Regulations"	the Uncertificated Securities Regulations 2001 of the UK (SI 2001/3755) (as amended)

"CREST"	the relevant system (as defined in the CREST Regulations) for paperless settlement of share transfers and holding shares in uncertificated form which is administered by Euroclear
"Deferred Shares"	the 30,000 redeemable deferred shares of £1 each in the capital of the Company
"Directors"	the directors of the Company as at the date of this Document, whose names are set out on page 7 of this Document
"Disclosure Guidance and Transparency Rules" or "DTR"	the Disclosure Guidance and Transparency Rules made by the FCA pursuant to section 73A of the FSMA, as amended from time to time
"Document"	this AIM admission document
"Dorset"	Dorset Exploration Limited, a company which was incorporated and registered in England and Wales with company number 04982511
"Dowgate"	Dowgate Capital Stockbrokers Limited, a company incorporated and registered in England and Wales under the Act with company number 02474423
"Egdon"	Edgon Resources U.K. Limited, a company incorporated and registered in England and Wales under the Act with company number 03424561
"ENI"	the Italian oil and gas multinational
"Euroclear"	Euroclear UK & Ireland Limited, a company incorporated and registered in England and Wales under the Companies Act 1985 with company number 02878738
"Existing Ordinary Shares"	the 345,613,985 Ordinary Shares in issue as at the date of this Document, being the entire issued share capital of the Company
"Existing Share Capital"	the issued ordinary share capital of the Company as at the date of this Document
"Exploration PL090 Licence"	the exploration licence block of the PL090 Licence
"FCA"	the UK Financial Conduct Authority
"Finance Manager"	Rodney Mooney
"First Oil" or "FOEL"	First Oil Expro Limited (in Administration) Limited, a company incorporated and registered in England and Wales under the Act with company number 01021486
"Former Directors"	the former directors of the Company who resigned on 31 July 2017, Kurt Portmann and Jeremy Edward Stuart King
"Founder"	Optiva
"FSMA"	the Financial Services and Markets Act 2000
"Group"	the Company and its subsidiaries from time to time
"IFRS"	International Financial Reporting Standards as adopted by the European Union

"Infrastrata"	Infrastrata PLC, a company incorporated in England and Wales under the Act with company number 06409712
"ISAs"	Individual Savings Accounts
"Jamaica JOA"	a joint operating agreement dated 1 March 2018 executed by Tullow Jamaica and UOG Jamaica relating to the Assigned Interest and defined the respective rights and obligations of the parties concerning operations and activities under the Contract
"Joint Venture Partners"	the joint venture partners as described in paragraph 4 of Part I of this Document
"Listing Rules"	the listing rules made by the FCA pursuant to section 73A of FSMA, as amended from time to time
"London Stock Exchange" or "LSE"	London Stock Exchange plc
"Main Market"	the regulated market of the London Stock Exchange for officially listed securities
"MAR"	the Market Abuse Regulation (EU) No 596/2014
"NPI Agreement"	an agreement dated 23 February 2017 between Corallian and Infrastrata plc pursuant to which Corallian undertook to pay to Infrastrata sums in respect of profits made as a result of the production of petroleum from the P1918 Licence
"Official List"	the Official List of the UK Listing Authority
"OGA"	the Oil and Gas Authority, an independent government company established by the UK Government in its current form on 1 October 2016
"Options"	an option to subscribe for an Ordinary Share
"Optiva" or "Optiva Securities"	Optiva Securities Limited, broker to the Company, who are authorised and regulated by the FCA
"Optiva April 2018 Warrant Instrument"	the warrant instrument executed by the Company constituting the Optiva March 2018 Warrants, details of which are set out in paragraph 11.30 of Part VII of this Document
"Optiva April 2018 Warrants"	warrants created pursuant to the Optiva April 2018 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva April 2018 Warrant Instrument
"Optiva December 2017 Warrant Instrument"	the warrant instrument executed by the Company constituting the Optiva December 2017 Warrants, details of which are set out in paragraph 11.20 of Part VII of this Document
"Optiva December 2017 Warrants"	warrants created pursuant to the Optiva December 2017 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva December 2017 Warrant Instrument
"Optiva Warrants"	warrants created pursuant to the Optiva Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the Optiva Warrant Instrument

"Optiva Warrant Instrument"	the warrant instrument executed by the Company constituting the Optiva Warrants, details of which are set out in paragraph 11.16 of Part VII of this Document
"Ordinary Shares"	ordinary shares of £0.01 each in the capital of the Company
"Panel"	The Panel on Takeovers and Mergers in the UK
"PCJ"	Petroleum Corporation of Jamaica
"P2264 Licence"	United Kingdom Offshore Licence No. P2264 dated 1 December 2014 (executed 4 March 2015)
"P2366 Licence"	United Kingdom Offshore Licence No. P2366 dated 20 September 2018 (executed dated 20 September 2018)
"PEDL 330 Licence"	United Kingdom Onshore Licence No. PEDL 330 dated 21 July 2016 (executed 15 September 2016)
"PEDL 345 Licence"	United Kingdom Onshore Licence No. PEDL 345 dated 21 July 2016 (executed 15 September 2016)
"PDMR"	a person within the Company who is: (a) a member of the administrative, management or supervisory body of the Company; or (b) a person who acts as a director of the Company whether or not officially appointed to such position; or (c) a senior executive who is not a member of the Board who has regular access to inside information relating directly or indirectly to that entity and power to take managerial decisions affecting the future developments and business prospects of the Company
"P1918 Licence"	United Kingdom Offshore Licence No. P1918 dated 1 February 2012 (executed 14 June 2012)
"PL090 Licence"	United Kingdom Petroleum Production Licence No. PL090 dated 30 May 1968
"Podere Gallina Farm-In Agreement"	the farm-in agreement entered into on 4 May 2017 between UOG UK and PVO
"Production Sharing Agreement"	the production sharing agreement dated 16 October 2014 originally entered into between Tullow Jamaica and the PCJ relating to the Walton Basin and Morant Basin licence consisting of Blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a Portion of Block 1, offshore Jamaica
"Prospectus Rules"	the prospectus rules made by the FCA pursuant to section 73A of the FSMA, as amended from time to time
"Prospex"	Prospex Oil and Gas Plc, a company incorporated and registered in England and Wales under the Act with company number 03896382
"PVEL"	Po Valley Energy Limited, a company incorporated and registered in Australia
"PVO"	Po Valley Operations Pty Ltd, a company incorporated and registered in Australia

"QCA Code"	the Corporate Governance Code for small and mid-size Quoted Companies published by the Quoted Companies Alliance (as amended from time to time)
"Registrar"	Share Registrars Limited, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 4715037
"RIS"	regulatory information service
"Securities Act"	United States Securities Act of 1933
"September 2018 Placing Warrants"	warrants created pursuant to the September 2018 Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the September 2018 Warrant Instrument
"September 2018 Warrant Instrument"	the warrant instrument executed by the Company constituting the September 2018 Placing Warrants, details of which are set out in paragraph 11.31 of Part VII of this Document
"Shareholders"	holders of Ordinary Shares
"Standard Listing"	a Standard Listing under Chapter 14 of the Listing Rules
"Standard Segment"	the standard listing segment of the Official List
"Swift"	Swift Exploration Limited, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 4736197
"Stelinmatvic"	Stelinmatvic Industries Ltd, a company incorporated and registered in England and Wales under the UK Companies Act 1985 with company number 5123578
"The Companies Acts"	the Companies Acts 1963 to 2013 of Ireland
"TIDM"	Tradable Instrument Display Mnemonic
"Tullow Jamaica"	Tullow Jamaica Limited, a company incorporated and registered in England and Wales under the Act with company number 09162755
"UK" or "United Kingdom"	the United Kingdom of Great Britain and Northern Ireland
"UK Companies Act 1985"	the UK Companies Act 1985, as amended
"UK Government"	the government of the UK
"UKLA" or "UK Listing Authority"	the FCA acting in its capacity as the competent authority for listing in the UK pursuant to Part VI of FSMA
"uncertificated" or "in uncertificated form"	a share or other security recorded on the relevant register of the relevant company concerned as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of CREST
"United States" or "US"	has the meaning given to the term "United States" in Regulation S of the Securities Act
"USD"	United States dollars, the lawful currency of the United States

"UOG Colter"	UOG Colter Limited, a company incorporated and registered in England and Wales under the Act and with company number 11143916
"UOG Ireland"	UOG Ireland Limited (formerly known as United Oil and Gas Limited), a company incorporated in Ireland under The Companies Acts and with company number 559743
"UOG Italy"	UOG Italia S.r.l, a company incorporated in Italy and with company number 14361161004
"UOG Jamaica"	UOG Jamaica Limited, a company incorporated and registered in England and Wales under the Act and with company number 11066439
"UOG PL090"	UOG PL090 Limited, a company incorporated and registered in England and Wales under the Act and with company number 10164996
"UOG UK"	UOG Holdings Plc, a company incorporated and registered in England and Wales under the Act and with company number 10358067
"UOG Warrant Instrument"	the warrant instrument executed by the Company constituting the UOG Warrants, details of which are set out in paragraph 11.17 of Part VII of this Document
"UOG Warrants"	warrants created pursuant to the UOG Warrant Instrument, issued by the Company to subscribe for new Ordinary Shares on the terms and conditions set out in the UOG Warrant Instrument
"VAT"	UK value added tax
"Vendors"	the shareholders of UOG UK as at 25 July 2017, such shares having been acquired by the Company pursuant to the Acquisition Agreement
"Voting Rights"	all the voting rights attributable to the capital of the Company which are currently exercisable at a general meeting
"Waddock Cross PL090 Licence"	the Waddock Cross licence block of the PL090 Licence
"Walton-Morant Licence"	the Walton Basin and Morant Basin licence consisting of Blocks 6, 7, 9, 10, 11, 12, 17, 25, 26, 27 and a Portion of Block 1, offshore Jamaica
"Warrants"	warrants to subscribe for new Ordinary Shares, further details of which are set out in Part VII of this Document

PART XI

GLOSSARY OF TECHNICAL TERMS

Please see the glossary of technical terms in Parts VIII and IX

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